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BONNEVILLE POWER ADMINISTRATION [BPA] RATES AND RESOURCE PLANNING

MF 184

HEARINGS

ORIGINAL

BEFORE THE

SUBCOMMITTEE ON
MINING, FOREST MANAGEMENT, AND BONNEVILLE
POWER ADMINISTRATION

OF THE

COMMITTEE ON
INTERIOR AND INSULAR AFFAIRS
HOUSE OF REPRESENTATIVES

NINETY-EIGHTH CONGRESS

FIRST SESSION

ON

H.R. 3177

BONNEVILLE POWER ADMINISTRATION FAIR RATEMAKING ACT OF 1983
AND
OVERSIGHT ON BONNEVILLE POWER ADMINISTRATION [BPA] RATES
AND
RESOURCE PLANNING

HEARINGS HELD IN WASHINGTON, DC
OCTOBER 27 AND 28, 1983

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BONNEVILLE POWER ADMINISTRATION [BPA] RATES AND RESOURCE PLANNING

THURSDAY, OCTOBER 27, 1983

House of Representatives,
Subcommittee on Mining, Forest Management,
and the Bonneville Power Administration,
Committee on Interior and Insular Affairs,
Washington, DC.

The subcommittee met at 10 a.m., in room 1324 of the Longworth House Office Building, Hon. James Weaver (chairman of the subcommittee) presiding.

Mr. Weaver. The subcommittee will be in session.

We are here to hold an oversight hearing on the Bonneville Power Administration and legislative hearings on H.R. 3177.

I welcome the public, the press, witnesses, and my fellow Members of Congress to these hearings of the House Interior Subcommittee on Mining, Forest Management, and the Bonneville Power Administration.

Today, we will focus on Bonneville Power Administration revenue, repayment, rates and ratemaking. Tomorrow, the subjects will be the cost effectiveness of resuming construction of WPPSS 3 and BPA's implementation of the conservation features of the Northwest Power Planning Council's 2-year action plan.

At a hearing of the Subcommittee on Water and Power Resources of the full Interior Committee 6 years ago, December 1977, leading up to the eventual enactment of the Regional Power Act, I stated that the decline in electricity use then being experienced in the Pacific Northwest was not a flash in the pan and that it meant that the region did "not need to rush into construction of extremely costly plants that will saddle citizens of Washington, Oregon, Idaho, and Montana with sharply higher electric bills." I said that, and these are quotes that I'm giving you: "We have time to carefully study how to solve our energy problems—not just finance a crash program for disaster." "There is enough electricity now for everyone if we marshal our resources carefully."

I said then that electricity rates will go way up to finance nuclear projects that would turn out to be extremely expensive. I noted that:

> Nuclear powerplants, for instance, are 10, 20, and 30 times as expensive as existing power sources in the Northwest. That is not 10, 20, or 30 percent more; that is 10, 20, or 30 times as expensive. So our rates are going to go up. The only way that we can assure the cheap rates is to conserve to keep our whole rate structure down. It is going to hurt our economy badly as these rates go up and we are saddled with plants that we may not even need.

Six years ago, WPPSS had sold only $1.8 billion in bonds and had spent even less on its nuclear projects. At that time, BPA and WPPSS estimated that it would cost only another $1.6 billion to finish WPPSS 1, 2, and 3. By mid-1982, however, WPPSS had sold $8.4 billion in bonds for its nuclear projects.

Now that money has all run out. Wall Street will not buy any more WPPSS bonds. The cost of constructing WPPSS 2 and preserving WPPSS 3 is now being paid directly by BPA ratepayers, who are also paying over $600 million a year to WPPSS bondholders. In the meantime, BPA has repaid essentially none of the $8 billion Federal investment in the Northwest power system since 1979—when payment of WPPSS debt service began.

While BPA collected about $1.4 billion net from its customers during fiscal year 1983, the new rates scheduled to take effect next week are designed to collect $2 billion during fiscal year 1984 and more than $2.2 billion during fiscal year 1985. This amounts to a revenue increase exceeding 50 percent and is the largest absolute dollar rate hike in BPA history. Although the aluminum industry is recovering from the recession, there remains serious doubt whether BPA will be able to recover this amount of revenue from its utility customers in the Northwest and in California.

In addition, the latest budget revision submitted to Congress shows continued large growth in BPA's revenue requirements through fiscal year 1988.

How can BPA raise the money? Despite the large rate increase taking effect next week, BPA expects over the next 2 years that its preference customer load will increase by more than 10 percent, its industrial load will increase by more than 37 percent, and its sales to California will increase by 13 percent, even though the Pacific Intertie has been essentially full for the past year. These assumptions appear quite optimistic.

What if these loads and revenues for BPA do not materialize? How long can BPA continue to avoid repayment of principal and interest to the U.S. Treasury?

In a report issued yesterday, the General Accounting Office concluded that BPA's repayment methodology is faulty and recommended that it be replaced with a "cost-based method incorporating a fixed annual repayment schedule." If BPA is put on a fixed schedule for repaying the Treasury, will BPA need to ask Congress for appropriations to keep the Federal Columbia River Power System operating? Will BPA be able to make payments to holders of WPPSS bonds? The GAO report stated, and I quote:

> Bonneville's success in achieving its forecasted revenues is highly dependent on the accuracy of forecasted electricity sales. For the past 10 years, Bonneville has overestimated electricity sales. In addition, the extent of deviation between actual and forecasted sales has been increasing. Although Bonneville has made changes in its forecasting methodology, in 1982, in response to this overestimation problem, it does not appear that Bonneville has solved it. Between June 1982 and June 1983—

and I continue to read from the GAO report:

> Bonneville overestimated average loads by 8.5 percent. Bonneville's estimates for other load categories such as peak and industrial loads were also high. If this degree of overestimation continues, Bonneville's forecasted 9.5 percent increase in power sales over a 2-year period may not occur, again leaving Bonneville with a revenue shortfall.

AVAILABLE

The Regional Power Act assigns to the Federal Energy Regulatory Commission the duty to ensure that BPA's rates cover its revenue requirements, including repayment of the Federal investment. But in a report issued yesterday, FERC stated, and I quote:

> The Commission lacks the power to modify the rates or other remedial powers that would assure that the Commission's statutory mandate is carried out. Moreover, the lack of clearly defined congressional standards has led to dispute as to the Commission's proper role. The scheme of Commission review of Federal rates has not been a workable one at this point. The present scheme allows the power marketing authorities to decline to comply with the Commission's orders. Furthermore, there are additional practical limitations in the Commission's ability to assure recovery of the Federal investment in the projects within a reasonable period of time, particularly in light of declines in the rate of growth in demands for power, coupled with increased capital investment, particularly in the Pacific Northwest.

Due to BPA's refusal to maintain the accounting system required by the FERC order, the Commission yesterday took what it called "the extreme measure of denying approval of Bonneville's 1983 transmission rate increase."

I understand, and this is merely something reported to me by hearsay, that the Chairman of the Commission also said that Bonneville is filled with renegade blackjack dealers. I will be asking the BPA Administrator soon if he is a blackjack dealer.

I won't have to go to Reno. I'll just go up to Portland. [Laughter.]

BPA's potential future revenue shortfalls also affect distribution of the electricity rate burden in the Northwest. If BPA interprets the Regional Power Act's post-June 1985 "rate tests" to hold down prices to preference customers and direct service industries, and that's an important part of the Northwest Power Act, then the Residential Exchange, designed to achieve rate parity for all of the region's residential consumers, may fail, frustrating a primary purpose of the act.

BPA's implementation of the rate provisions of the Regional Power Act has also been criticized by the customer groups, many of which would prefer the ratemaking procedure proposed in H.R. 3177, introduced by Representative Wyden of Oregon, which would direct an independent hearing officer to produce an initial decision based solely on the record in the proceeding instead of merely compiling the record for use by the BPA Administrator.

These are important issues, central to the financial solvency of the BPA. I note that we have a vote in the House. I'm going to ask other members if they have any opening statements. After that, we'll go vote and come back immediately.

Are there other opening statements by other members?

[No response.]

Then the committee will recess for 5 minutes to make the vote.

AFTER RECESS

Mr. **Weaver**. Before proceeding to our first witness, and without objection, let us have printed H.R. 3177 at this point in the hearing record.

[The bill, H.R. 3177, follows:]

I

98TH CONGRESS
1ST SESSION

H. R. 3177

To amend the Pacific Northwest Electric Power Planning and Conservation Act to protect the rights of parties to proceedings undertaken to establish the rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power by the Bonneville Power Administration.

IN THE HOUSE OF REPRESENTATIVES

MAY 26, 1983

Mr. WYDEN (for himself, Mr. SWIFT, Mr. AUCOIN, Mr. BUNKER, Mr. LOWRY of Washington, and Mr. WILLIAMS of Montana) introduced the following bill; which was referred jointly to the Committees on Interior and Insular Affairs and Energy and Commerce

---

A BILL

To amend the Pacific Northwest Electric Power Planning and Conservation Act to protect the rights of parties to proceedings undertaken to establish the rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power by the Bonneville Power Administration.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That this Act may be cited as the "Bonneville Power Administration Fair Ratemaking Act of 1983".

SEC. 2. Subsection (i) of section 7 of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839 et.seq.) is amended as follows:

(1) strike out subparagraphs (A) and (B) of paragraph (2) and substitute:

"(A) any person shall be provided a reasonable opportunity to submit oral and written materials;

"(B) any person shall be provided an adequate opportunity by the hearing officer to offer refutation or rebuttal of any material submitted by any other person including the Administrator;

"(C) the hearing officer, shall allow a reasonable opportunity for cross-examination which, as determined by the hearing officer, is not dilatory, in order to develop information and material relevant to any such proposed rate, and

"(D) if the Administrator requests, before the close of the record of the hearing, the hearing officer shall allow the Administrator to file revised rates, provided that the hearing officer shall then allow adequate opportunity for cross-examination of such revised rates and any material submitted to support such rates and, for good cause shown, to offer rebuttal of such revised rates or supporting material.";

(2) strike out paragraphs (3), (4), and (5) and substitute:

"(3) After the record of the hearing has been closed, the hearing officer shall accord persons who have participated in the hearing a reasonable opportunity to file proposed findings of fact and conclusions of law respecting the establishment of rates pursuant to this section.

"(4) As expeditiously as practicable after receiving proposed findings of fact and law pursuant to paragraph (3) of this subsection, the hearing officer shall publish an initial decision on the rates to be established pursuant to this section.

"(5) No interested person, including the Administrator or his staff, shall make or knowingly cause to be made to the hearing officer during the hearing and prior to the publication of his initial decision on rates any ex parte communication relevant to the merits of the hearing, nor shall the hearing officer make or knowingly cause to be made to any person, including the Administrator or his staff, an ex parte communication relevant to the merits of the hearing.

"(6) Any person who participated in the hearing may file exceptions to the hearing officer's initial decision with the Administrator within thirty days of the publication of the initial decision.

"(7) Rates determined by the hearing officer pursuant to paragraph (4) of this subsection shall become the final rates of the Administrator unless, within sixty days of the publication of the initial decision, the Administrator makes a final decision establishing rates that are different than those of the hearing officer, in which case the rates established by the Administrator are the final rates of the Administrator. Any such different rates shall be based on the record assembled by the hearing officer pursuant to the hearing conducted pursuant to this subsection. In any final decision establishing rates that are different than those established by the hearing officer, there shall be included a full and complete justification of the differences between the final rates established by the Administrator and those established by the hearing officer.";

(3) renumber paragraph (6) as paragraph (8); and

(4) add the following new paragraph at the end thereof:

"(9) For purposes of this subsection 'person' includes the Pacific Northwest Electric Power and Conservation Planning Counsel.".

○

Mr. WEAVER. I will restrict all witnesses to 5 minutes in their oral testimony, with the exception of Mr. Johnson, if he wishes more, and all written statements will, by unanimous consent, without objection, so ordered, be part of the record.

Mr. Johnson, I will defend your integrity at any time, I can assure you, from either facetious or serious remarks. I'm told that it was not a blackjack dealer, but a person wielding a blackjack, that the regulatory commissioner referred to, if, indeed, he referred to anything at all.

So I can vouch for the integrity of Mr. Johnson here and now, and I'm privileged to have him here before this committee. Won't you begin, sir?

STATEMENT OF PETER JOHNSON, ADMINISTRATOR, BONNEVILLE POWER ADMINISTRATION, ACCOMPANIED BY STEVEN AILSHIE, BPA FINANCIAL MANAGER, ED SIENKIEWICZ, BPA POWER MANAGER, AND HARVEY SPIGAL, BPA ACTING GENERAL COUNSEL

Mr. JOHNSON. Thank you, Mr. Chairman. My name is Peter Johnson. I'm the Administrator of the Bonneville Power Administration. I have with me today three gentlemen who will assist me in responding to your questions. On my left, to your right, is Ed Sienkiewicz, our power manager; on my right, your left, is, first, Steve Ailshie, our chief financial officer and then Harvey Spigal, our general counsel.

I will ask them to assist me in responding to questions that you may have. But before that, I do have a few informal comments that I would like to make.

It remains the highest priority of this Administrator to assure the fiscal strength and viability of the Bonneville Power Administration. Certainly, this includes the assurance that we have set rates adequate to generate the revenues that we require. It is certainly our intent, and I believe it's reasonable to expect, that we will reestablish our repayment integrity with respect to the U.S. Treasury.

I must keep in mind, however, as the Bonneville Administrator, that I have statutory responsibilities, and I must also take into account the regional impact of the Bonneville Power Administration's actions.

In our 1983 rate case, just filed and for which we've now received interim approval, I have taken generally the following firm actions. The first is to firm up our rates and, obviously, the revenues that will flow from that. Second, to adjust rates within the region to the changed conditions that we face. And finally, to increase the confidence that I have, as the Administrator, and others have in the fiscal viability of the Agency.

With respect to increasing revenue certainty, let me just mention some of the actions that have been taken since a year ago in our last rate case and are incorporated in this rate case.

First of all, we have used independent and improved load estimates, which are far superior, I think, in terms of meeting the state of the art than on previous occasions.

Second, we have provided for a 5-percent capital financing through revenues. This is a departure from previous policy.

The third, we have automatic adjustment clauses for the WPPSS projects and also for Residential Exchange to assure full recovery of these costs in this rate period.

Next, we have a customer charge for our direct service industrial customers that will help stabilize industrial loads and the revenues that we expect from this important customer group.

Next, a readiness-to-serve charge for our generating customers is new.

Finally, we have flexible marketing features in our surplus firm and non-firm energy rates, something that I think will inure to the benefit of the Agency in terms of assuring its revenue integrity.

In addition to that, we have taken action to improve our financial and fiscal management. This starts in the area particularly of increased export marketing. Much work has been done, and meetings have been held by parties within the region as well as without. I am pleased with the progress being made there, which I think will help us assure the financial and fiscal integrity of Bonneville.

Next, we have taken strong steps to make certain that we are looking at realistic operating levels and the costs that will be necessary to maintain those levels within the Agency. We have found efficiencies and cost improvements that are realized and are now reflected in this rate case.

We are improving our financial analysis and reporting system. This has been a maturing process within the agency, and since I've been the Administrator, I have put priority emphasis on the development of a sound financial management information system to assist us not only in operating and control but also in supporting our rate development processes.

We are also seeking aggressively at this time, although we have run into some difficulties, what we call off-balance sheet borrowing, so that we would then be able to supplement the agency's borrowing from the U.S. Treasury as required. And I think you know, Mr. Chairman, that we have been successful in this regard, preliminarily, anyway, in the case of the Eugene Water and Electric Board, with the vote that was just taken in that community.

We are also improving our building and our procedures in order to increase cash flow.

These actions are going to be seen, I'm sure by all parties, as very significant and effective over time. I'm certainly pleased to witness, as the Administrator of Bonneville at this time, the improving economy in the Pacific Northwest. That inures to the benefit of the Agency as well as those utility customers we serve, as well as the direct service industries.

In our 1983 rate submittal, the one that has just received interim approval by the Federal Energy Regulatory Commission, we have the following provisions in those rates.

First, to repay our deferral up to this point to the U.S. Treasury, which is $236 million. In addition to that, we will make our current principal payment—we call that amortization—of $225 million. This accumulates to $451 million to cover current principal payments and to catch up on the deferred payments that have accrued over previous years.

I want to note that this is in addition to current interest on outstanding obligations to the U.S. Treasury, which in 1984 amount to $367 million, in 1985, $406 million. So those would be added to the number that represents the deferral payment and the amortization payment.

We believe that this at this time signals not only within the region, but to the U.S. Congress and to the executive branch, the Agency's determination to meet our fiscal responsibilities to the Treasury.

This, of course, is backed by the Federal Columbia River Power System revenues, and I would conclude only by saying that I believe, as the Administrator at this time, having taken these actions, that we are entering a period of stronger fiscal performance by the Agency and performance adequate, certainly, to meet all of our costs, including payments to the U.S. Treasury.

That concludes my informal comments, Mr. Chairman. I'd be happy to answer your questions.

Mr. **Weaver**. Thank you very much, Mr. Johnson. Mr. Johnson, in press release issued by the Bonneville Power Administration on Friday, September 30, of this year, less than 1 month ago, the press release states: "Substantial cuts in programs and adjustments of cost allocations enabled us"—BPA—"to hold down the rate increase." It goes on to say this rate increase of 22 percent is the lowest of the annual rate increases that have occurred since 1980. "As the demand for power and costs associated with thermal plants stabilize, the trend has been for rate increases to subside."

Is it not true that, actually, by this rate increase you anticipate the largest single revenue increase in Bonneville's history from 1 fiscal year to another?

Mr. **Johnson**. I stand by the comment made in that news release. It was 22 percent.

Mr. **Weaver**. That isn't my question, sir. My question is this: Do you not anticipate, your figures anticipate, the largest single annual revenue increase in the history of Bonneville?

Mr. **Johnson**. I believe we will have to look into the factors upon which you're relying in making that statement.

Mr. **Weaver**. Mr. Johnson, what were your revenues in the previous fiscal year?

Mr. **Johnson**. I'll have to look at those numbers.

[Pause.]

I think, Mr. Chairman, that you are concerned about the complete makeup of the Bonneville revenue structure, which turns on loads and load expectations and what we will expect in the way of growth there. But it also takes into account the Residential Exchange, and that is a very complex——

Mr. **Weaver**. I want to start by saying, Mr. Johnson, that we have netted out the Residential Exchange in everything we do. And also, because you use 3 different years—by that, I mean you use a 20-month year, a calendar year, and a fiscal year, which is very confusing—we have to, in order to try to keep order in our study of Bonneville, limit ourselves to one set of figures. So we use fiscal years. We'll be talking about fiscal year 1984, primarily. We also net out the Residential Exchange, which is, I think, much better to do, and I would ask you to do it in everything you give us. Just net out the Residential Exchange. Take out what washes and just put in what actual, real revenue increases or decreases are required.

So I'm talking now about netting out the Residential Exchange in terms of what cash you actually net receive. So do you have the figures? I have them here from your Bonneville budget, but it would be nicer if you'd read them.

Mr. **Johnson**. I think it's important, I agree with you, that we make certain that we're not only talking about the same fiscal periods, but that we're also making the proper assumptions and the same assumptions with respect to how to treat such complex areas as the Residential Exchange.

I'm going to ask Steve Ailshie to respond to the question that you ask.

Mr. **Weaver**. Surely.

Mr. **Johnson**. He'll be able to go through these numbers in more detail.

Mr. **Ailshie**. You'll have to bear with me in not being able to net out——

Mr. **Weaver**. Would you talk louder, sir, please?

Mr. **Ailshie**. You'll have to bear with me in not being able to net out the Exchange numbers immediately, because that was not the way we came prepared to respond to them.

The 1983 revenue level that we had included in our budget plan was $1.884 billion.

Mr. **Weaver**. Is what, sir?

Mr. **Ailshie**. $1.884 billion.

Mr. **Weaver**. In other words, a $1 billion increase for fiscal year 1984.

Mr. **Ailshie**. Our 1983 revenue level that we were anticipating just prior to the time that we had concluded our financial results for 1983 was $1.884 billion.

Mr. **Weaver**. Right.

Mr. **Ailshie**. Our estimated revenue level for fiscal year 1984 is $2.772 billion.

Mr. **Weaver**. So how much net increase is that?

Mr. **Ailshie**. It's somewhere around $800 million.

Mr. **Weaver**. $800 million.

Mr. **Ailshie**. Yes, sir.

Mr. **Weaver**. $900 million. The figure actually, netting out the Exchange is $556 million. So use either figure, Mr. Johnson. Is this not the largest single annual revenue increase in Bonneville's history?

Mr. **Johnson**. I can't respond to that directly. I'd be happy to answer for the record. I haven't made that particular analysis. I focused, instead, on the rate increase.

Mr. **Weaver**. Maybe Mr. Ailshie could give us an answer. Mr. Ailshie, has Bonneville ever had a $556 million or a $900 million increase from 1 year to the next?

Mr. **Ailshie**. No, sir. Let me say that that is the largest absolute dollar increase, I think, without checking it.

Mr. WEAVER. Would you accept Mr. Ailshie's testimony, Mr. Johnson?

Mr. JOHNSON. Yes; he would be more accurate on that than I.

Mr. WEAVER. All right. Would you please say that this is the largest absolute increase in Bonneville's history?

Mr. JOHNSON. I'd be happy to confirm his comments, yes.

Mr. WEAVER. Just please say it. I would like you to say it.

Mr. JOHNSON. This is the happy—this is the happiest moment I've had. [Laughter.]

Seriously, the absolute increase is the largest in the history of the Bonneville Power Administration.

Mr. WEAVER. Thank you very much, Mr. Johnson. And so, therefore, your press release that says that this is the lowest of the annual rate increases is, and I won't ask you to comment on this, is quite misleading in the sense that what you're really anticipating is sharply higher rate increases.

Would you please describe—is my time up yet? OK. Excuse me. We're all, of course, limited to 5 minutes. My time is up. But we're going to have a number of rounds, as many as the members want. And the Chair would recognize the gentleman from Idaho for his 5 minutes.

Mr. CRAIG. Thank you very much, Mr. Chairman. Mr. Johnson, in light of the FERC decision, obviously, I think some questions have to be asked around that, because that's been a concern of a lot of ours and people in the Northwest for sometime, who have the responsibility.

Do you think that Congress should basically enact legislation which would set standards for FERC to follow in modifying or overseeing Federal power marketing administration rates?

In other words, I'm saying in large part it's been determined, not only by your observation and your decisions but by FERC's hesitancy, that there's a gray area out there that has been not properly defined by Congress, itself.

What is your reaction to that and your reaction to yesterday's decision?

Mr. JOHNSON. First of all, I want to assure this committee and the Federal Energy Regulatory Commission that we will comply with their orders. There's no question about that.

I feel that the issue that arose yesterday with respect to their action on our transmission rate submittal to them arose out of misunderstandings. I think that I accept most of the responsibility—we do in Bonneville—for having not properly communicated nor advised them of the process by which we are going to comply with the orders that they have issued.

I think it's important to note that, in connection with the power rates that were given interim approval yesterday, that it is my belief, and this has been confirmed both by staff and also by informal visits with commissioners, that they are very happy with the developments and the expertise by which our staff, as well as theirs, are interrelating in that regard.

So I would say that, as the law exists, it is meeting the needs not only of the Federal Energy Regulatory Commission, but so, too, of the Bonneville Power Administration.

I feel that we can do the same thing as it relates to transmission rates. We have to recognize that we have come into a period of incredible change under the Regional Power Act, giving the agency not only the responsibility, but the authority, to engage in much broader ratesetting processes. And we're in our third year into that now. It has taxed our staff, obviously, as well as what I consider the interface with the staff of the Federal Energy Regulatory Commission.

I would only report, Congressman, that I am pleased with that progress. And I don't see the need for change at this time. I think what we need is a closer communication, a better understanding. And together, I think we can work out what differences remain.

Mr. CRAIG. In other words, you're saying that you don't believe there is any need for congressional action to clarify roles, that the reaction yesterday and the action taken by FERC is a failure to communicate, and that there is latitude and proper instructions within the law to allow these, your entity and FERC, to interface properly?

Mr. JOHNSON. Yes, I believe so, Congressman. And we're committed to making it work within the context as it exists.

Mr. CRAIG. How long is it going to take you now to come up with a new proposal for rate increases as it relates to the denial yesterday?

Mr. JOHNSON. I'll ask Mr. Sienkiewicz, our power manager, to respond to that question directly.

Mr. SIENKIEWICZ. Mr. Congressman, we really haven't had a chance to review the order and its mechanics. We do have staff analyzing it now. We don't believe necessarily that the order would require us to redo the transmission submission, but to comply with the previous order relative to the way in which accounts, tranmission accounts, are constructed.

So it's something that perhaps could be done very rapidly. We really haven't had a chance to assess it.

Mr. CRAIG. In an attempt for me to understand it better, and your statement, Mr. Johnson, that you will comply, and as it relates to the rate increases that were discussed previously by you and the chairman, in your compliance, are we to see a rate adjustment downward based on FERC's reaction yesterday, and decision?

Mr. JOHNSON. I don't think so, necessarily. I think what they're concerned about is the timeliness within which we have reacted to an order that they have issued. I couldn't predict at this time that there will be any change in the rate.

We believe it's a sound rate, soundly developed. But we obviously want to respond to the instructions of the commission and will intend to do that. But I know of no change at this time that will result.

Mr. SIENKIEWICZ. I would second that as well. I think the difficulty we have here is the question of whether or not the commission has adequate information in order to discharge their responsibility. They have asked for more information. I think it's up to us to give it to them. I believe that, once having done so, that will be supportive of the rates that we filed.

Mr. CRAIG. Do you believe that, based on what your plans are as it relates to accounting procedures and reporting procedures and all that you're talking about revising and changing with inside BPA, that we're going to be able in the future to avoid these kinds of—I guess the word I think that can be properly used is "confrontations" between BPA and FERC?

Mr. WEAVER. The time of the gentleman has expired.

Mr. CRAIG. Could I allow him to answer the question?

Mr. WEAVER. Surely.

Mr. JOHNSON. Yes, I believe you'll see that cure rapidly.

Mr. CRAIG. Thank you.

Mr. WEAVER. I always forget to say that it's the announced standard practice of this committee to swear in all Government witnesses. So I'll ask you to raise your right hands, please do. Pursuant to rule 8-B of the rules of the committee, I'm going to ask you to testify under oath. Raise your right hand.

Do you swear the testimony you're about to give is the truth, the whole truth, and nothing but the truth, so help you God?

Mr. JOHNSON. I do.

Mr. SIENKIEWICZ. I do.

Mr. AILSHIE. I do.

Mr. CRAIG. Mr. Chairman.

Mr. WEAVER. Yes.

Mr. CRAIG. Does this mean that anything they've said to date should not be entered into the record because it was not taken under oath?

Mr. WEAVER. It can be in the record.

Mr. CRAIG. Well, I ask unanimous consent that any statement made prior to the taking of the oath be considered and entered into the record.

Mr. WEAVER. Reserving the right to object, I'm not quite sure what the gentleman's request means. Under my reservation of objection, I state that everything they have said up to now is in the record. But it would not be under oath.

Mr. CRAIG. Well, I just ask unanimous consent that the record show that it was taken or that it was received under oath.

Mr. WEAVER. Oh, I don't think we can do that. The oath wasn't taken.

Mr. CRAIG. Well, but we can do it by unanimous consent, unless somebody objects.

Mr. WEAVER. All right, by unanimous consent, but the court would have to decide that.

Mr. CRAIG. Well, this isn't a court. [Pause.]

Mr. WEAVER. It just simply can't be imposed retroactively, I tell my friend, and therefore it would be moot. OK?

Mr. CRAIG. Well, then, let's, I guess, get our act together and keep the oaths up front as we begin these meetings.

Mr. WEAVER. Exactly.

Mr. CRAIG. Either that or forget that foolish diatribe.

Mr. WEAVER. I do not consider it foolish.

Mr. CRAIG. I do, Mr. Chairman. Thank you.

Mr. WEAVER. The gentleman from Colorado.

Mr. KOGOVSEK. Thank you, Mr. Chairman. Mr. Chairman, I have no specific questions of Mr. Johnson. It's good to see him again. It's good to have you back in front of our committee. I think the last time, Mr. Johnson, I had a chance to listen to your testimony was about a half year ago, 6 months ago. And after that hearing or during that hearing, I didn't feel a whole lot of optimism on our side. I got the impression that there was not a whole lot of optimism back then as far as BPA and WPPSS and so on.

Are you more optimistic now than you were, say, 6 months ago as to the success of the whole program and so on?

Mr. JOHNSON. Very, very definitely. We still have our problems and we're working them out one by one. We have made a lot of progress since I saw you last, Mr. Congressman.

Mr. KOGOVSEK. That's all I have, Mr. Chairman.

Mr. WEAVER. The gentleman from Arizona.

Mr. MCCAIN. Thank you, Mr. Chairman. One of the problems that we are facing in this country and in Arizona today is the credibility of the utility companies as to whether their word is good, whether we can depend on what their forecasts are.

I would like to just also pursue a little bit the chairman's line of questioning here. In response to the chairman, you said that it is the largest absolute—meaning pure dollars, not accounting for inflation—increase in history. The chairman made reference to a press release that you had made which indicated that it was one of the lowest.

For the record, maybe you could clarify the disparity between those two statements.

Mr. JOHNSON. Yes, Mr. Congressman. As the chairman has pointed out, in absolute numbers, this is the largest increase in total revenue requirements that the agency has experienced. The comment that I made in the news release that this is the lowest since 1980 of rate increases in terms of percentage over the previous year is also accurate. It turns on larger loads and obviously other considerations.

Now the chairman has said that he has netted out the Exchange, but that has to be taken into account in evaluating those numbers.

However, on previous occasions, because of particularly the costs being taken into the Federal Base System of debt service on the net-billed projects, those are the nuclear projects being constructed by the Washington Public Power Supply System, our rates rose rapidly. And this obviously had an impact on our economy.

Since becoming Administrator, I have attempted to find out what we could do about that, and we have put very strict controls on a number of areas, not only there but also internally within the agency, and in our commitment to conservation at this time—not in terms of our ability to develop the capability to acquire conservation, but instead, the actual acquisition of kilowatthours through that mechanism at this time.

And the result of all of that has been an increase of 22 percent on our priority and preference rate to our public agency customers. I, frankly, am very pleased with that and am very proud of it, as a matter of fact, to be able to keep the rate increase that low. We see it, as a matter of fact, reaching an area where I am prepared to predict it is plateauing. I do not see the kinds of increases that we have suffered in the last 3 or 4 years continuing into the future.

As I responded to the Congressman earlier, I think we have our matters under control, and our worst is behind us.

BEST [illegible] AVAILABLE

Mr. McCain. Thank you. Mr. Chairman, I would like to point out that my colleague, Congressman Chandler from Washington, is here, and he has followed with great interest and certainly has a great deal of concern about this issue. He's here with us, and I thank you for being here today.

According to the GAO report, Mr. Johnson, it concluded that the BPA's repayment methodology is faulty and recommended that it be replaced with a "cost-based method incorporating a fixed annual repayment schedule."

Could you comment on that, please?

Mr. Johnson. There's no denying that, based upon our performance over the last several years, one would have to conclude that the current methodology, which has flexibility to accommodate the uncertainties faced by the agency, has been less than satisfactory. I believe it can be made to work. And at the present time, as I have indicated earlier, I am making it work. The numbers that we have in this current rate case to repay not only our deferral of interest to the Treasury, but our current principal obligations plus all interest, I'm sure will be met.

What the GAO, properly, is assessing is our past performance, which has been less than satisfactory. So they introduce the possibility of a fixed amortization schedule, one based upon cost accounting principles. That certainly is something that could be considered. As a matter of fact, it's my understanding that it's been under consideration for years, long before I became the Administrator. Perhaps it's necessary and desirable to revisit it at this time.

However, we must recognize that, under the rate directives in the law that the Administrator operates under, I am not empowered to create contingencies or funds or allowances, if you will, for uncertainties. I am to cover costs and make my best possible judgment calls on what those costs will be.

So, if suddenly I go on a fixed amortization schedule and the agency runs into the uncertainties like we have in the last several years, including the economic downturn, these cost overruns on the Supply System, plus some bad water years—you have to understand that we're on a hydrobased system—then I would have to have some provision, under whatever that change of law might direct, to provide for such contingencies. Maybe it would be another line of credit, if you will, borrowing from the Treasury in order to cover shortfalls when they occur.

But we're certainly engaged in discussion and dialog. We responded to the GAO, as well as FERC and others, with respect to this subject. But I feel right now that we're demonstrating we can make the current methodology work.

Mr. Weaver. The time of the gentleman has expired. He will, of course, be entitled to another series, as many as he wishes.

The gentleman from Wisconsin.

Mr. Moody. Thank you, Mr. Chairman. Pardon my ignorance, but what is the legal structure for paying for facilities that are not yet on line? To what extent are current ratepayers paying for future to-be-built facilities in this whole rubric?

Mr. Johnson. Very significantly, Congressman. It is a function of the terms and conditions of, I think, the bond covenants that require that the Federal agency, Bonneville, take into its rate base all debt service on the construction that has been completed so far on these so-called net billed projects, the nuclear thermal resources, none of which have been completed and none of which are generating kilowatthours yet.

So, as the chairman said, there is some $600 million in debt service to cover outstanding indebtedness that was used to construct resources that are not yet completed.

Mr. Moody. This is basically a CWIP-type of issue, then.

Mr. Johnson. Yes.

Mr. Moody. Construction work in progress. Is that $600 annual debt service? What's the timeframe for that, then?

Mr. Johnson. That's annual, roughly.

Mr. Moody. What's the underlying debt that that reflects?

Mr. Johnson. I'm going to use the number $6 billion. It might be corrected, but it's in the range of $6 billion.

Mr. Moody. What is the probability of that and the optimistic timeframe for those facilities to start generating revenue?

Mr. Johnson. Let me take them individually.

Mr. Moody. OK.

Mr. Johnson. WPPSS 2 is moving toward completion at this time. It is scheduled to load fuel in November of this year and become commercially operable in 1984. Work is continuing, and there is nothing to suggest that those dates will not be met. However, I think we all have to understand that there are just—it takes time, and there are difficulties, and we want to make sure that when we do, in fact, bring up WPPSS 2, that it is safe and meets all quality standards of the Nuclear Regulatory Commission, as well as those of our utility and the Washington Public Power Supply System.

So we will have kilowatthours in 1984. They will be generating revenues to help offset those costs.

With respect to WPPSS 1, which is also, like WPPSS 2, situated at Hanford in Washington, it is presently in a preservation state, and there is no determination at this time as to a restart. It is estimated that it will be down for roughly 5 years, and it would be coming on in 1991.

WPPSS 3 at Satsop, WA, is also moving toward a state of preservation. It is estimated that it will be preserved or mothballed for 3 years. Then it will be restarted and completed.

So two of the units are presently in a state of suspension; one is moving toward completion.

Mr. Moody. Now when that one, that WPPSS 2, does come on line, is that late or mid-1984? Or do you know?

Mr. Johnson. The fuel loading is 1983 in November, as I said, and the commercial operation date I want to say is March or April 1984.

Mr. Moody. When that does come on line, will you be able to sell that power for a rate which will recover, begin to recover, your capital costs in addition to your variable costs?

Mr. Johnson. Yes; I'm going to ask our power manager, because that's a good question, and it deserves a comprehensive response. I'm going to ask Mr. Sienkiewicz to respond to that, because that generation, of course, comes into the Federal Base System, and it will be used to serve not only firm load within the region, but also it factors into our firm surplus and the rate that we have recently set for that. But we have made the conclusion, I can say, that it is prudent utility practice to complete that project, bring it into the Federal Base System, and operate it this time in anticipation of the rates that we will receive for its output.

Ed, would you expand on that?

Mr. SIENKIEWICZ. Yes, Mr. Congressman. The rates which we have currently filed include the full cost of that project, the full fixed costs, plus the variable costs. When it does come on line, we expect the variable costs to be less than 10 mills per kilowatthour, and we also would expect that, if in fact that would add to near-term surpluses, that we could market those near-term surpluses for rates in excess of that amount.

So we think that that is a sound near-term economic determination.

Mr. MOODY. So you can cover all of your variable costs and begin to recover some of your fixed costs.

Mr. SIENKIEWICZ. Yes.

Mr. MOODY. But you don't know exactly what part of the fixed costs yet.

Mr. SIENKIEWICZ. We have already recovered, in a sense, the fixed costs by virtue of having included them in the rates. I think the only issue is whether or not——

Mr. MOODY. You're recovering them on people using other facilities.

Mr. SIENKIEWICZ. That's correct.

Mr. MOODY. Cross-subsidizing, in effect.

Mr. SIENKIEWICZ. It is part of the resource mix that is used to determine the rates for our preference customers and is reflected in their rates currently.

Mr. WEAVER. Would the gentleman yield?

Mr. MOODY. Certainly.

Mr. WEAVER. The gentleman's question is excellent, but he's not getting an answer. The gentleman's question was whether you will be able to recover your capital costs of the plant selling it at 10 mills.

Suppose the plant—and this is what the gentleman from Wisconsin, I'm sure, intended to ask—suppose it was all by itself and you were operating WPPSS 2 as an individual unit. What rate would be required to recover its capital costs as well as its operating costs?

Mr. SIENKIEWICZ. For that individual unit, Mr. Chairman, probably around 50 to 60 mills per kilowatthour.

Mr. WEAVER. About 50 to 60 mills per kilowatthour. And you anticipate selling it for about one-fifth that cost, perhaps a little higher. Is that correct?

Mr. SIENKIEWICZ. Yes.

Mr. WEAVER. So, therefore, you're going to recover about one-fifth the cost. I just want that for the record. I thank the gentleman from Wisconsin for raising that issue.

Mr. MOODY. You hope to sell something—if I understood your answer—you hope to sell for something above 10, because 10 would just cover your variables. Does that clarify?

Mr. Sienkiewicz. The variables, I'm not certain precisely what that number is. It is less than 10 mills per kilowatthour.

Mr. Moody. OK. So at 10, you're beginning to touch or recover your capital. But, as the chairman points out, to fully recover the capital, the so-called average total cost, ATC, would be about 50. Is that right?

Mr. Sienkiewicz. Yes; I think I should point out that that resource is being planned on to meet firm obligations in the region for a long period of time. We have included the capital costs of that resource, plus the anticipated variable costs, in the rates. They are designed to serve our firm power customers.

Now looking at it solely on an incremental basis in terms of what it does when it first comes on line, if in fact the output is not immediately needed to meet firm obligations, we're saying that we can more than cover the variable costs and, therefore, that is economically a prudent decision.

Mr. Moody. More than cover the variable costs by selling it as surplus power to California or other places?

Mr. Sienkiewicz. That's correct.

Mr. Weaver. The time of the gentleman has expired. I thank him very much for the question. What the respondent was saying is that we're going to be selling the cheap hydropower in order to pay for the nuclear. That's, of course, what this whole WPPSS project has been about, to mortgage our hydropower to build these plants.

I will now ask unanimous consent to allow our distinguished colleague from the State of Washington to participate in the questioning, and I'm sure that the committee will approve. Without objection, it's ordered. But I will go first to a member, the gentleman from Arizona, Mr. McNulty.

Mr. McNulty. Mr. Sienkiewicz, I note since the hearing in Eugene last summer, in anwer to question 8, that BPA has revised its figure of surplus power to 1,000 average megawatts. Is that a revision upward or downward from what number we had last summer?

Mr. Sienkiewicz. I believe that's a revision upward, Mr. Congressman. I don't recall precisely what we said in the hearing in July. Our current estimates are for firm surplus in this operating year of a little in excess of 1,000 average megawatts. That came unfolded during the conduct of our recent rate case and I believe that number was slightly increased from the initial proposal to the final proposal because of the way in which some of our public agencies were disposing of their own resources.

Mr. McNulty. That puts terrible pressure on your rate structure, doesn't it?

Mr. Sienkiewicz. It does put pressure on our rate structure, yes.

Mr. McNulty. What progress has been made since the summer hearing in Eugene in terms of additional transmission facilities from the Northwest either to southern California or the Southwest?

Mr. Sienkiewicz. I can only report that discussions are proceeding between Northwest and Southwest parties with respect to the potential for additional transmission. We are optimistic, because those discussions have been constructive.

Mr. McNulty. Why are you optimistic? Who has said what with respect to the possibility that this company or that company might be interested in building the line?

Mr. Sienkiewicz. I think at this point we are optimistic, because all of our economic analysis indicates that there is sound economic support for additional intertie capacity to California, to the south. And we believe that through discussion, once this is wholly understood, that the economics will be persuasive.

Mr. McNulty. Doesn't that suggest that the Northwest is in an almost permanent state or semipermanent state of enormous quantities of surplus energy?

Mr. Sienkiewicz. No, sir, it does not. Our forecast currently, based upon, if you will, our median expectations about future load growth, would have the Northwest in the firm surpluses of the magnitudes that it currently has for about 3 years and then declining to load/resource balance around 1988, 1989.

Mr. McNulty. Why would anyone build a substantial transmission line that wouldn't be able to be used for a rather long period of years? What would you regard as the minimum time period that you could expect to utilize fully a 500kV, for example, intertie line? How many years do you want out of that before you would consider building it?

Mr. Sienkiewicz. It depends, sir, on the expectation about the availability of not only firm surpluses, but also additional amounts of nonfirm energy going from the north to California.

Currently, we are not able to move all of the nonfirm energy that we have available at some times of the year. And we believe that some additional amount of intertie capacity is justifiable economically solely on the basis of increased economy transactions.

Mr. McNulty. You talked in terms of things, and I think you used the verb "moving along." What tangible progress has been made toward building additional transmission facilities southward?

Mr. Sienkiewicz. We have identified in a working group between the Northwest and Southwest utilities in which there has been participation by the Northwest Power Planning Council as well as the California Energy Commission, a number of alternatives through a subcommittee on transmission. They are currently focusing on four major alternatives and they are examining both the economic and engineering aspects of those alternatives with a calendar to complete the analyses by early next calendar year.

Mr. McNulty. My final question, Mr. Chairman: Mr. Spigal, is Bonneville Power Administration, under the law, entitled to any protection under the various titles of the Bankruptcy Act, and has that ever been considered as an alternative to your current plans?

Mr. Spigal. You asked whether Bonneville Power Administration is entitled to protection under the Bankruptcy Act?

Mr. McNulty. Yes.

Mr. Spigal. The Bonneville Power Administration is an agency of the Federal Government, and Bonneville would not file a petition for bankruptcy. Bonneville would not be subject to the Bankruptcy Act, nor would any Federal agency.

Mr. McNulty. Your answer is no.

Mr. Spigal. No.

Mr. McNulty. Thank you. Thank you, Mr. Chairman.

Mr. Weaver. I thank the gentleman. The Chair will inform the gentlemen that the subcommittee held hearings in Oregon in July on the intertie question with a great number of expert witnesses from various parts of the West. And those hearings will be printed next week and should be most interesting reading.

The Chair recognizes our distinguished colleague from the State of Washington.

Mr. Chandler. Thank you very much, Mr. Chairman and members of the committee, for this privilege. I'd like to, if I may, go back to Mr. Moody's question and to yours just for a clarification of the points that I think were made.

If you had charged a rate of 50 mills to cover the amortization of this new plant, as I believe the chairman may have suggested, wouldn't you have amortized in a very short period of time the entire debt that Bonneville faces and perhaps even a good deal more, if the economy of the Pacific Northwest could have withstood such a shock?

My point is that, if you build a plant like Grand Coulee in the 1930's, that's at a cost that reflects 1930's costs. If you build a nuclear powerplant in the 1970's and 1980's, that reflects today's costs and it's bound to be different. But you don't adjust your rates to reflect all of the costs of the 1980's, unless I'm just terribly confused by the question.

You simplified it to the point of saying, if you had that plant by itself, you'd have to charge 50 mills. But we don't have that plant by itself, and so what you've done is averaged. And that average, then, covers the cost of the amortization of that plant.

Is my understanding incorrect?

Mr. Johnson. That is correct. That is common utility practice. Our rates are based upon costs. And so the cost of new resources, which today are much more expensive than earlier resources, are melded into that cost base.

I think it's important to point out that in June of this year, we took into the resource base of the Bonneville Power Administration the second powerhouse recently completed at the Bonneville Dam. And that was much more expensive than the rates that we are charging at the present time.

But I think that that was a sound utility decision to bring the second powerhouse at Bonneville into our resource base.

Mr. Chandler. You received a letter from me, and I think a number of others in our delegation, at least, from the State of Washington, expressing concern about the aluminum industry and the increase in rates. Could you update the committee on what action has been taken with regard to those direct service customers?

Mr. Johnson. It starts sometime back, Mr. Congressman. The only way you're going to keep rates down is to keep costs down. The only way that you can do this is to make sure that you are firm in your evaluation and decisions, to make sure that you are not eroding the viability of the utility, its reliability, and the quality of its power. But, at the same time, you're keeping costs as low as possible.

As the chairman alluded to earlier, in my announcement of our rate increase, we have taken a number of steps to keep costs down.

That is reflected in the rates that we are now publishing that will be charged to our direct service industrial customers. Had we not kept those costs down, had we not taken the action that we have, then the situation would have been far more serious than it is.

We are not happy with the rates that we're charging anyone. I would rather that we had no increases this last year. But BPA must remain fiscally viable, as I have mentioned before. The rate of 26.8 mills per kilowatthour that will be charged to the industries represents roughly a 9-percent increase over this last year. They're unhappy with that rate. They say that this clearly puts them in a category that would be described as "swing"—meaning that, when the markets for aluminum drop, the price for aluminum drops, they may have to close their pot lines down. Frankly, we have been in that mode for the last 2 years. But, nonetheless, we believe that certainly at the present time the rates signal to them that it is economically viable for them to remain at risk in the region, meaning simply that they will operate and, frankly, they are. They are operating at above even what we expected they would be operating.

We can't take assurance in that, therefore, their problem is cured. It's not. Neither is that of the irrigators in the region because of these cost increases and consequent rate adjustments. We will continue to work with the direct service industrial customers between now and the next rate case, where they come into another system by which rates will be set, to do everything we possibly can within the law and within the balance that the Administrator must exercise between rate classes, including public agency customers as well as private utilities that may put a load on the agency.

So, the rates are allowing them to continue in the region. They're not as low as they would like them to be. I hope that that answers your question.

Mr. CHANDLER. Yes, it does. And thank you, Mr. Chairman, for your courtesy.

Mr. WEAVER. It's the committee's pleasure to have you. Just a very brief note. WPPSS 2 is operating at a staggering loss—according to their testimony, will operate at a staggering loss. I was a real estate developer. I built buildings. I'd have 10 profitable buildings and then I'd stupidly go ahead and build another one that I operated at an enormous loss and I'd have to subsidize that 11th building with my profits from the others.

That's what Bonneville is doing here. So what they're doing is taking our cheap hydro electricity, raising the rates on the hydro sharply higher to your constituents and mine in order to pay for the staggering loss at WPPSS 2 and then the cost of WPPSS 1 and 3 as well. So that's what's involved, and I think it's well to understand that that's what's going on.

Now the reason that I——

Mr. CHANDLER. Would the chairman yield?

Mr. WEAVER. Surely.

Mr. CHANDLER. I'd really appreciate it, because I think there's a difference between your analogy of nine profitable buildings and one unprofitable one, and that is the fact that the customers are not common to those buildings. In this case, the customers are all common, and what you're doing is you're adding supply common to the entire region.

So I think perhaps the analogy was a faulty one.

Mr. **Weaver**. No; the idea is the person you're worried about is you, the businessman, whether you make a profit or not. Because this businessman, Bonneville, whatever his losses are, is going to make your ratepayer pay for it. And that's the difference.

Now the reason that I emphasize, Mr. Johnson, the higher revenues, the fact that this is historically the highest revenue increase in Bonneville's history, and, of course, the year before it was also the record high increase and the year before that was a record high increase, is that, if you do not get those revenues, you're going to become insolvent. You're not going to be able to pay the bills that you owe, that you project that you owe. And the GAO report, which I read into the record, says that Bonneville, for the past 10 years, has consistently overestimated its load forecasts by 8½ percent every year. And therefore, what Bonneville is doing now is saying, we're going to raise our rates sharply, not as high as we have before, but 22 percent. But we anticipate almost 50 percent more revenues. In other words, the higher the price, the more we're going to sell. That's what they're saying. They're going to sell 10 percent more to the public utilities and 13 percent more to California and 37 percent more to the direct service industries on top of this rate increase.

Well, as a businessman, that is not usually what happens. As a matter of fact, my fight with WPPSS and the Bonneville Power Administration for the last 10 to 12 years has been that they have not cranked in the price elasticity of demand. As a matter of fact, the Pacific Northwest Utility Conference Committee load growth forecasts for many years did not even use price elasticity in order to anticipate their load growth.

I simply said all along, if you're going to increase your rates sharply because of the cost of these plants, you're going to have not as much electricity used. And what I said, of course, proved completely correct, and it's happened.

And the GAO has said, yes, Bonneville has increasingly overestimated its revenues and sales of electricity. If they don't get this revenue, they won't be able to pay the bills.

Now what I want to do, Mr. Johnson, is to show what your costs have done over the last few years. So I'm going to ask unanimous consent that your cost figures from the Bonneville Power Administration figures be placed in the record at this time and I'll go over a few of them.

In fiscal year 1979, your total costs—and I net out Residential Exchange at all times—were $316 million. In fiscal year 1983, 4 years later, they had jumped to $1.331 billion. That's net of the exchange. And in fiscal year 1984, they jumped to $2.109 billion.

So, in 1979, $316 million. Suddenly this enormous increase to $1.3 billion and $2.1 billion. Yes?

Mr. **Moody**. Would the chairman yield? Are those in constant dollars or is inflation built into that?

Mr. **Weaver**. These are all just plain ordinary old dollars.

Mr. **Moody**. OK. So they're current dollars?

Mr. **Weaver**. Yes; plain ordinary old dollars. [Laughter.]

Now the question I have for you, Mr. Johnson, is this: Bonneville projects for fiscal years 1986–87, and 1988, figures—which would include Residential Exchange, and we can't net them out because you've not given us any other figures for WPPSS payments or interest or conservation or Residential Exchange—but they go sharply higher. And why do you project such sharp increases to, in 1986, $3.6 billion; in 1987, $4.1 billion; and in 1988, $4.5 billion?

What's causing this increase in revenues, projected revenues?

Mr. JOHNSON. May I ask Mr. Ailshie to assist me in the response to that question in those out year budget estimates? Steve, would you——

Mr. AILSHIE. Yes; I'd like to address, first of all, the statement about the 1983 net number that you quoted a moment ago. Our actual expenses for 1983 was $1.768.7 billion.

Mr. WEAVER. Yes; as I say, I always net out Residential Exchange. I tell my committee colleagues that the Northwest Power Act has what's called a Residential Exchange. In other words, it was a device to subsidize the residential consumers of the private utilities. And there was a provision in the Northwest Power Act to do this.

And so Bonneville buys electricity from the private utilities at their base cost and resells electricity to them, but it's a wash. It really doesn't happen. It's a bookkeeping thing. BPA sells them electricity at Bonneville's base cost, which is cheaper. So, therefore, you see, the difference is the subsidy.

Now, the costs in here have only the money that Bonneville is paying the private utilities. What you have to do is net out the difference between what Bonneville pays for it and what the private utilities pay BPA. That's what I'd call the net exchange cost to BPA.

So, really, here where we have in 1983 $544 million in Residential Exchange cost, it's actually a net $106 million. So it's really $1.331 million, Mr. Ailshie. But whatever figures you want to use are fine.

My time has expired.

Mr. AILSHIE. Well——

Mr. WEAVER. I'm sorry. My time has expired, and I'll get to you afterwards.

The gentleman from Idaho?

Mr. CRAIG. Yes, Mr. Chairman. I would like two unanimous consents. One, our colleague, Carlos Moorhead, has a statement that he would like entered into the record.

Mr. WEAVER. Surely. Without objection, so ordered.

[EDITOR'S NOTE.—The prepared statement of Hon. Carlos J. Moorhead, referred to by Mr. Craig, may be found in the appendix.]

Mr. CRAIG. And in line of the questioning that you were following, I would be pleased to hear the completion of that response, if you would continue.

Mr. AILSHIE. I was just going to correct the number that we were using there in terms of the $1.768 billion, which is the total operating expenses for fiscal year 1983. If you adjust the Residential Exchange out of that, my numbers would indicate that the adjustment for the Residential Exchange should take somewhere between, around $550 million off of the $1.768 billion. So that the number that we were using earlier would be somewhere around $1.2 billion.

Mr. CRAIG. I couldn't hear you on that, with the clattering in the room. Would you speak more into the mike, please? Just pull it closer, if you can.

Mr. AILSHIE. The numbers that were quoted, the $316.3 million in 1979, and the $1.331 billion in 1983, I was just going to correct, at least from the records I have, the total operating expenses for fiscal year 1983 based on our preliminary accounting results, are $1.768 billion. And the residential exchange numbers are somewhere in the range of $550 million. The number I have is $535.9 million plus $7.7 million. And that would be closer to $1.250 billion in 1983 as opposed to the $1.331 billion.

I'd be glad to reconcile those numbers.

Mr. WEAVER. Would the gentleman yield?

Mr. CRAIG. Yes, I'd be glad to yield, Mr. Chairman.

Mr. WEAVER. Mr. Ailshie, the $544 million is your gross cost of the Residential Exchange. We net it out. In other words, we take out the difference between what you receive and what you pay out, which is a net $106 million in 1983, giving you $1.331 billion. Now you can do that, I'm sure.

Mr. AILSHIE. I understand. The fact is, though, that the increase in the Residential Exchange numbers since 1979 is a total number, not a netted out number. Those loads were never on Bonneville in 1979, and they are brand new loads and revenues to Bonneville as a result of the Regional Act.

So in comparing revenues and revenues, you've got to compare revenues without the Residential Exchange in total. That was all I was getting at.

Mr. WEAVER. Would the gentleman yield for just one point?

Mr. CRAIG. Yes, if you'll consider my time for additional questions, Mr. Chairman.

Mr WEAVER. Surely. But I've got to get Mr. Ailshie to understand this, or we won't be using the right figures.

Mr. Ailshie, I'm talking about the net figures, the actual cost to Bonneville or its customers. We're using Bonneville figures as well. You've changed them a bit; $544 million is your gross Residential Exchange cost. We net out the difference between what you pay and what you receive. And that's a net $106 million. Do you understand?

Mr. AILSHIE. I understand, yes.

Mr. WEAVER. All right. Let's use the net Residential Exchange. In other words, the real money, not what washes. OK? Real dollars. The gentleman from Idaho.

Mr. CRAIG. Thank you very much, Mr. Chairman. Trying to develop a perspective or an understanding on a time spread as it relates to rate increases in the region, both to residential and DSI customers, can you give us a spread of percentage increase in rates, say from about 1977 through 1983 for DSIs?

Mr. JOHNSON. The question, Mr. Congressman, is what was the rate to our direct service industrial customers in 1973, for instance, versus what it is in this last rate case? It was in the range of 3 mills per kilowatthour at that earlier time. And as I said earlier, it is 26.8 now.

Is that correct?

Mr. SIENKIEWICZ. Yes, that's correct.

Mr. CRAIG. What percentage increase does that represent?

Mr. JOHNSON. Roughly 1,000 percent.

Mr. CRAIG. Roughly 1,000 percent. I guess the obvious question from that is, in that timeframe of inflation, cost of doing business, and all of that, that seems like a very exorbitant increase. If I were having to pay 1,000 percent increase in the cost of doing business over a 6-year timespan, I'd probably be out of business.

Now, either you are cheap on in 1977 or you're extremely high today. I mean, that would be a reasonable conclusion to draw. What is your response to that?

Mr. JOHNSON. I agree. I think the rate before was extremely low, thanks to our inheriting the hydrosystem in the Pacific Northwest, and I certainly feel that the rate today is higher, certainly, than any party believed that it would be as few as 2½, 3 years ago.

Mr. CRAIG. There is concern on the part of all citizens out there that are under the BPA system that we are seeing basically what I think can be reasonably called phenomenal rate increases. In the case of the DSIs, where it is estimated that they consume less, in essence, than they actually pay for and there is a subsidy involved that is passed on through, who does that subsidy go to?

Mr. JOHNSON. It would be difficult for me, Congressman, to characterize anything that is occurring as a subsidy. I certainly have no authority to grant such.

Mr. CRAIG. Well, I know. It's a matter of terminology. I guess if you're paying more than what you get or use, and I understand the relationship of why that happens, then where does that spread go? We won't call it a subsidy, then.

Mr. JOHNSON. I don't think we can. Obviously, if somebody were to believe that any particular customer class is paying a higher average figure than others, then it would be to the benefit of the other rate classes, all of them, from nonfirm through the priority firm and perhaps even the surplus sales figure, as well as the firm power rate to private utilities within the region.

But I think that that would be an unfair and an inappropriate conclusion or characterization of what has occurred.

We have to go back and look at how we got where we are. In the bargain struck in passage of the Regional Act, the direct service industrial customers, in order to gain 20-year contracts, long-term contracts, from Bonneville, were willing to take on the exchange, which was that net amount between Bonneville's rate and the average rate of the private utilities in the region necessary to bring the domestic and rural customers of those private utilities down to a parity with the Bonneville rate.

So it is not Bonneville increases in cost that have driven the DSI rate up. It has been the increased costs of the private utility systems.

Mr. CRAIG. OK. Well, then, if it is true that your DSIs consume about 17.7 percent of BPA capacity and pay about 22 percent of the revenue and that your, you know, investor-owned utilities and residential customers consume about 73 percent and pay about 56 percent, under that relationship, then, the difference is a holding down of power rates for residential and utility-owned customers?

Mr. Johnson. That could be a proper interpretation of the result. In other words, with them paying, if the numbers you represent are accurate, and I believe that that is roughly the case——

Mr. Craig. They are somewhere close.

Mr. Johnson [continuing]. Then others would be the net beneficiary of that difference at this time.

Mr. Craig. When we look at the Pacific Northwest and the number of users of the system, where would the bulk of that price-depressing or priceholding activity reside? Oregon? Washington? Or Idaho?

Mr. Johnson. Well, let's see.

Mr. Craig. Percentagewise.

Mr. Johnson. It would go, our biggest loads of the agency are those of our preference and priority customers, our public agency customers. I would have to guess that the State of Washington probably has more load than the other States. But it would be shared by all States.

Mr. Craig. I understand.

Mr. Johnson. Probably proportionate to the load they place on the Administrator. But the largest load just happens to be in the State of Washington. Mr. Sienkiewicz, would you——

Mr. Craig. For DSI's or for the residential?

Mr. Sienkiewicz. No; For the Residential Exchange, I would guess that the largest load would be in the State of Oregon. We have two investor-owned utilities there, Pacific Power & Light Co. and the Portland General Electric Co. About two-thirds of the residential load in the State of Oregon is served from the investor-owned utilities.

Mr. Weaver. The time of the gentleman has expired.

Mr. Craig. Thank you.

Mr. Weaver. And I would say to the gentleman the answer is correct. It's the State of Oregon, because we have the Pacific Power & Light and Portland General Electric utilities.

Mr. Craig. So, in other words, this relationship, Mr. Chairman, that causes this disparity in pricing, ultimately Oregon is the beneficiary of it.

Mr. Weaver. Exactly, the major beneficiary, right.

Mr. Craig. Thank you.

Mr. Weaver. The gentleman from Wisconsin.

Mr. Moody. I'd like to go back to the question that I was asking before, and then Mr. Chandler also asked. The response you gave to him seemed to differ from what you're giving to me. Could you go over that again? Let me see if I can frame the question.

The hydroplants obviously have cheaper fixed costs because those are historically older and have lower costs from that earlier era; right? However, as plants get older, often their variable costs begin to climb higher. Typically, for an older plant of any variety, the fixed costs are low, but variable costs are high versus a new plant that has new technology. And you can expand the size of your operation to get the lowest point on your total cost curve so that your fixed costs, then, dominate and your variable costs get lower.

So were you only referring to the fixed cost component in that discussion or were you talking about total costs? Is the hydro also substantially lower when all costs are taken into account or only when fixed costs are taken into account?

Mr. Sienkiewicz. When all costs are taken into account.

Mr. Moody. OK. Hydro is still substantially lower.

Mr. Sienkiewicz. Yes, sir.

Mr. Moody. Now you have shrunk from the word, avoided the word "subsidy." But you talked about beneficiaries of the spread a little while ago. Isn't that another word for "subsidy"?

Mr. Johnson. I think of a subsidy as something that results from a conscious action, perhaps arising out of law and instruction under law.

Mr. Moody. What about ratemaking? That's a conscious action.

Mr. Johnson. I have followed precisely the law and the rate directives that I am instructed to follow in setting the DSI rate. And it happens to result in them paying the rates, not unlike as characterized by Congressman Craig. But I have no authority to establish a subsidy for the direct service industrial customers under the authorities that I presently have.

Now if Congress were to pass——

Mr. Moody. Not an explicit authority, but ratemaking, unless it forces every user to pay exactly that incremental cost occasioned by his own use, if you vary, if you instead had some flat number where people have higher costs and then lower costs are given the same rates, pay the same amount, that is a subsidy. It's not a subsidy in the sense that you're using the term, but it is a subsidy.

If you, sir, receive power at a price higher than it would have cost to serve you, you are subsidizing somebody out there. And vice versa. If you are receiving power at a cost lower than the incremental cost to serve you, you are receiving a subsidy.

So let's not get hung up on semantics. We are taking what is analogous to a multiplant firm. Some plants have higher costs than others, and they are producing the same product. And you're charging the same price, in effect, to every class, certain class of users. Correct?

Mr. Johnson. In our preference customers, yes.

Mr. Moody. OK. So there's a subsidy built into the ratemaking. Let's not be afraid to say that. You are not providing what you might legally call a subsidy, but that is a form of subsidy.

Mr. Craig. Would the gentleman yield?

Mr. Moody. It may be justified. I'm not criticizing it. I'm just trying to clarify the concept.

Mr. Craig. Would the gentleman yield?

Mr. Moody. Certainly.

Mr. Craig. There's also a difference in the relationship of the power delivered, firm versus nonfirm power.

Mr. Moody. Right. So it's not an identical product, in that sense.

Mr. Craig. That's right.

Mr. Moody. That's right.

Mr. Craig. Is that not correct?

Mr. Johnson. That is correct, Congressman.

Mr. Craig. In your relationship as to your requirement to deliver.

Mr. Moody. Yes.

Mr. Johnson. That's correct.

Mr. MOODY. I'm happy to be corrected. But for those who are receiving the same product, either in the firm category or the nonfirm category, they are drawing on plants that have different cost structures; right? So my point still holds.

Let me get back to the aluminum industry in particular. What is the elasticity that you estimate in the demand for power in the aluminum industry? There certainly is not a vertical demand curve. It's a horizontal demand curve, which implies elasticity.

Mr. JOHNSON. I'll ask Mr. Sienkiewicz to respond to that. That's a good question.

Mr. SIENKIEWICZ. What we're finding, Mr. Congressman, is that the price elasticity with respect to electricity prices for the aluminum companies is a variable which is wholly dependent upon what the price of aluminum is. And you could have some prices of aluminum, there could be times at which you're going to have a relatively inelastic response and other times in which you're going to have a very elastic response.

Mr. MOODY. The higher aluminum goes, the more inelastic the demand for electricity.

Mr. SIENKIEWICZ. That's correct.

Mr. MOODY. OK. You have ranges of estimates, given reasonable upper and lower estimates? Do you have an interval? Do you have an interval estimate?

Mr. SIENKIEWICZ. Yes, sir, we do have it. I don't have it handy. I would have to provide it for the record.

Mr. MOODY. Could you provide that for the record?

Mr. SIENKIEWICZ. Yes, sir.

[EDITOR'S NOTE.—In response to Mr. Moody's question, the Bonneville Power Administration subsequently supplied the following additional information:]

Mr. Sienkiewicz. The following table of forecasted aluminum industry loads illustrates how loads vary as electricity rates change. What the table reveals is that price elasticity differs along a "demand curve," that is, according to what electricity price levels are of interest. In addition, price elasticities for alternative electric rate levels are different if the underlying assumptions regarding aluminum ingot prices are different (i.e., on different demand curves). To illustrate how to calculate elasticities from the table, the following example may be useful.

For a price change in January 1984 from 22.3 mills/kWh to 24.3 mills/kWh, given the low aluminum price scenario,

$$\text{elasticity} = \frac{\%\text{ change in aluminum loads}}{\%\text{ change in electricity price}}$$

$$= \frac{\dfrac{1711.8 - 1457.0}{1711.8}}{\dfrac{22.3 - 24.3}{22.3}}$$

$$= \frac{0.1488}{-0.0897} = -1.66$$

Thus, - 1.66 is the short-run price elasticity for that particular electricity price change, given that aluminum price scenario. However, using the same methodology, the short-run price elasticity for an electricity price decrease of about the same magnitude at the same time may be as high as -2.90 (for a change from 22.3 to 20.3 mills, low aluminum price scenario) or as low as 0 (same electricity price reduction, but high aluminum price scenario).

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FORECASTED ALUMINUM LOADS (Avg. MW)
(w/approximate elasticities associated with incremental price reductions)

Electricity Price (mills/kWh)

	27.3	26.3	25.3	24.8	24.3	23.3	22.3	21.3	20.3	19.3	18.3	17.3	16.3
High Aluminum Price Scenario													
JAN 1984	2309.8	2437.6	2633.4	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1
		(1.51)	(2.11)	(.48)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
JUN 1984	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1	2683.1
		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Low Aluminum Price Scenario													
JAN 1984	1353.0	1353.0	1457.0	1457.0	1457.0	1457.0	1711.8	1966.2	2157.3	2417.0	2570.1	2633.1	2633.1
		(0.0)	(2.02)	(0.0)	(0.0)	(0.0)	(4.07)	(3.31)	(2.07)	(2.44)	(1.22)	(0.45)	(0.0)
JUN 1984	1205.1	1205.1	1205.1	1205.1	1205.1	1205.1	1396.4	1681.1	1870.7	2062.5	2570.1	2633.1	2633.1
		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(3.70)	(4.55)	(2.40)	(2.08)	(4.75)	(0.45)	(0.0)

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Mr. Moody. Because, of course, we would be worried that, if you set rates irrespective of the impact upon the aluminum industry, you may be causing impacts far greater and far beyond your initial realization.

Mr. Sienkiewicz. Yes, sir. We think that that is a legitimate concern and one that we have taken into consideration in setting the rates.

Mr. Moody. What is the household elasticity demand?

Mr. Sienkiewicz. The short-term elasticity for residential is minus 0.2.

Mr. Moody. 0.2, which means that if you raise prices, you lower revenues.

Mr. Sienkiewicz. No; if you raise prices, you would increase revenue.

Mr. Moody. I'm sorry. It's inelastic. You raise prices, you increase revenues.

Mr. Sienkiewicz. Yes, sir.

Mr. Weaver. The time of the gentleman has expired. Sorry. The gentleman from Arizona, Mr. McCain.

Mr. McCain. Thank you, Mr. Chairman. I'd like to go back again to the statement about which he is trying to say is that they're selling cheap hydropower to build these plants. I appreciate the great success that the chairman had in the real estate business. However, I know of no businessman that I've ever been involved with who was so successful that didn't use a source of revenue that he had in order to generate revenues to expand his business, if he chose to expand it.

I find nothing in that philosophy here, and I would be curious, Mr. Johnson, how you would expect to build any expansion of your power-generating capability unless you used increases in revenues above cost from the hyropower that you have? Would you comment on that?

Mr. Johnson. Yes; I think that's a fair observation. We have, as a utility, a legal responsibility to meet the loads placed upon the Administrator. We take that charge very seriously. So we are at the present time planning to acquire resources, thermal, conservation, and hydro, all of which, most of which, will be at a cost above current rates. But we think that that is the appropriate utility decision to make at this time to make sure that we are, in fact, in a position to meet our loads.

Mr. Moody. Would the gentleman yield?

Mr. McCain. Sure.

Mr. Moody. I'm trying to get some understanding here. The businessman is not a monopoly. He has some competitors. He cannot simply raise the price of his current products to capture revenue to create some new product and open a new plant. He has to probably go borrow it and finance it, based on those revenues from that new plant. So a competitive businessman——

Mr. McCain. If I could reclaim my time——

Mr. Moody. Yes; I'm sorry.

Mr. McCain [continuing]. If a business, whether it be a monopoly or not, expects to expand, he's got to have some revenues in order to do so, to build facilities that do so. He, therefore, has to increase whatever he is charging for whatever product to make a profit so that he can further build. So whether he is monopoly or not.

Now, obviously, that businessman does not have FERC and laws passed which set the amount that he can charge or cannot charge, also.

Mr. Moody. But his competitors constrain that.

Mr. McCain. They certainly do. And so does Bonneville Power have their constraints. I certainly hope so. Yesterday, they were denied a rate increase, or the day before yesterday.

Mr. Moody. My point is that it's not analogous to a businessman, who cannot raise his price to capture revenue.

Mr. McCain. I would say to my colleague, if I could reclaim my time——

Mr. Moody. Sorry.

Mr. McCain. We can say it's not analogous; I contend that it is absolutely analogous.

Mr. Johnson. Congressman Moody, I might volunteer. My background is business. I am instructed by all laws governing the agency to administer its affairs in a business-like fashion. And at the present time, yes, we're a monopoly. But, constructively, we are attempting in every way to operate as a sound business and make sure that we are, in fact, the best value as it relates to the loads that will be placed upon the Administrator, competing with other alternatives available to consumers.

I think that this spirit, if you will, has taken form in action in the areas where we have, in fact, cut costs. And this is where I express to you my confidence that we are healing a situation that has, frankly, undergone significant change in the last few years.

Mr. McCain. Is, indeed, WPPSS 2 operating at a staggering loss?

Mr. Johnson. It is not operating yet. It will be a cost-effective resource when it comes into our resource base in 1984.

Mr. McCain. It will be cost effective?

Mr. Johnson. Yes; we consider it a sound purchase to add to our resource base to meet load.

Mr. McCain. Could you provide the committee with further information as to how you come up with those calculations that it will be cost effective?

We are having this hearing today, I believe, to examine rates and ratesetting. I'd like to go back to a first question that I asked.

I would hope that this committee would seriously consider, and you would consider, recommendations that the repayment methodology would incorporate a fixed annual repayment schedule. Along with that, if contingencies in the law are required, I think it would go a long way toward restoring credibility of future users, of people who have experienced these serious rises in their rates.

Mr. Chairman, I hope that that would be one of the ways that we could examine to proceed to correct the problems that we are having here. And also, I'm sure tomorrow we are going to, from my understanding of the schedule, we are going to talk about WPPSS 3. But that is obviously going to have a dramatic impact on what the future rates will be.

In the remaining time I have, would you comment on your position on WPPSS 3?

Mr. **Johnson**. I recommend to the Supply System in May of this year that they put it into a 3-year state of preservation. And that was because of our inability to finance at that time. We could not arrange conventional financing or short-term bank financing. I made a review as to whether we should attempt to finance WPPSS 3 to completion out of rates, and I made a conscious choice not to do that at that time.

I did, however, with respect to WPPSS 2, because it was 98 percent complete and very close to loading fuel and coming on line.

WPPSS 3, by contrast, is roughly 75 percent complete and requires another $1 billion to complete. Therefore, it was our recommendation to the Supply System that they put it into a state of preservation.

We consider it a viable resource. We see it in our forecasts as needed to meet load in the region. We would hope that the impediments to finance can systematically be overcome between now and some period within 3 years. However, before we would recommend to the Supply System and provide financing to restart that unit, we're going to be certain that it is a sound utility decision.

Mr. **Weaver**. The time of the gentleman has expired. Just simply to clear up our thinking here, of course, you use, and as a builder I used the revenues from previous buildings and profits to help me construct the next building. Of course that's what we did. Sure. But if my rents, my cost for the building, what I had to pay out to the banks and to other people, was 50 and my rents were 10, I would not build the building. I would use the money to build it, but I would have to get at least 50 back on rents if my costs were 50, or I'd be dumb to build it.

Now, they have testified that their costs are 50 mills for WPPSS 2 and they're going to sell it for 10 mills per kilowatthour, one-fifth the cost. That's what we're talking about.

Now, it they were going to sell that for 50 or 60 mills, then it would be a viable project. It is obviously not cost effective, as Mr. Johnson has said, because their testimony has said that they're selling the electricity for 10 mills and their cost is 50 mills.

So that's the difference. But you're subsidizing.

Mr. **McCain**. Mr. Chairman.

Mr. **Weaver**. I'd be delighted to yield.

Mr. **McCain**. Could I respond? I believe we went through this 10 mill versus 50 mill thing just a minute ago. Could Mr. Johnson comment on that again?

Mr. **Weaver**. Sure.

Mr. **McCain**. Thank you. Go ahead, Mr. Johnson.

Mr. **Johnson**. First of all, I think the significant difference in these analogies that we're trying to compare is that the Bonneville Administrator is a monopoly and I am charged by law to meet the loads placed upon the agency. I think that that is significant.

No. 2, there's no denying that WPPSS 2 is more expensive than the average of the resources upon which the agency relies. But I pointed out that we just brought on the second powerhouse of the Bonneville Dam, which may be in the same range. So we'll be selling that, to use his comparison, at something less than fully allocated costs. We consider that a sound business decision in order to add to our resource base to be able to meet load.

Portions of the conservation that we are currently acquiring also cost more. So, in a sense, you wish the analogy would comply in our acquisition of cost effective conservation.

I would hope that that would explain that in some more detail.

Mr. Weaver. OK. Thank you very much. The gentleman from Arizona, Mr. McNulty.

Mr. McNulty. I saw the term spot rate used in one of the answers to the questions. I hadn't previously heard that term used in the electric industry, but I guess it means what maybe I grew up calling energy or economy interchange, something that you got on a very short notice and something that you couldn't depend on perhaps for more than an hour.

Would that describe spot rate purchases?

Mr. Sienkiewicz. Yes, sir.

Mr. McNulty. What's a recent quote on a spot rate purchase per kilowatthour?

Mr. Sienkiewicz. Recently, the sales that have been made out of the region have been going somewhere between 20 and 30 mills per kilowatthour.

Mr. McNulty. On spot rate?

Mr. Sienkiewicz. They may not be so nonfirm as to be curtailable in an hour. Some of those are bilateral transactions between buyer and seller for 1 week duration, for example, but are still considered to be fairly short-term transactions.

Mr. McNulty. OK. Let's move up to something longer than that. I don't know what you'd call the next plateau of certainty, but something longer than a week and less than 15 years. Are there any intermediate range agreements being negotiated like that?

Mr. Sienkiewicz. Yes, sir, there are between utilities both in the Northwest and in California for varying periods. Some contracts have been signed for 2- or 3-year periods.

Mr. McNulty. OK. Let's talk about them. Two to 3-year period. Do you know the rate per kilowatthour?

Mr. Sienkiewicz. Those rates, I understand——

Mr. McNulty. The combined rate, the demand and the energy. Turn it into mills per kilowatthour.

Mr. Sienkiewicz. In the neighborhood of 35 mills per kilowatthour, I believe.

Mr. McNulty. OK. We would expect it to be slightly more than what we've called spot rate.

Mr. Sienkiewicz. Yes, sir.

Mr. McNulty. And what would be the next plateau up, then, after the 2 to 3 year?

Mr. Sienkiewicz. There may be a plateau even shorter than that. In fact, we have made a recent offer at our surplus firm rate of 31.4 mills, beginning November 1.

Mr. McNulty. For——

Mr. Sienkiewicz. For a period of up to 4 months.

Mr. McNulty. Well, that figures. That falls kind of between the brackets that you've established on the spot and the 2- to 3-year rate.

Take me a block or a bracket—I know these things aren't defined that well—but above or longer than the 2- to 3-year period.

Mr. Sienkiewicz. Well, some of the discussions that have gone on, general discussions between Northwest and California utilities, looking at a longer period of time, perhaps 10 to 15 years——

Mr. McNulty. Yes.

Mr. Sienkiewicz [continuing]. Would get you closer to 60 miles per kilowattthour.

Mr. McNulty. Well, and probably rightly so. Could you build a conventional coal-fired plant today and have a cost of less than 60 mills?

Mr. Sienkiewicz. I don't believe so.

Mr. McNulty. OK. Do you know of anything between the 2-to-3-year range, on the one hand, and the 10- to 15-year range on the other?

Mr. Sienkiewicz. I'm not aware of any current transactions that have been negotiated in between the range.

Mr. McNulty. If somebody could buy, if a seller of power could buy power for 30 to 35 mills per kilowatthour for all costs over a 3-year period, there would be very little incentive for them to do much in the way of building their own plants or in the terms of building additional transmission lines.

Is that not true?

Mr. Sienkiewicz. I don't believe that that would be an accurate conclusion, because, I think, if they were only depending upon this power for 3 or 4 years and not for their long-term firm obligations, that they could not depend upon a renewal of that form of contract. And therefore, having long-term responsibilities to meet their firm loads, they would have to look at their own construction or longer term purchases.

Mr. McNulty. How attractive would 30 mill power be to southern California, Arizona, New Mexico?

Mr. Sienkiewicz. It depends upon their alternatives. If, in fact, that's the lowest price that they—it's attractive enough to displace oil and gas-fired generation, but it may not be competitively attractive because they can find a cheaper source from another utility.

Mr. McNulty. Don't you know enough about the business to have a pretty good hunch as to whether or not 30-mill power would be cheaper than oil-fired?

Mr. Sienkiewicz. It is cheaper than today's oil-fired generation cost, yes.

Mr. McNulty. Or any other kind of costs, don't you imagine?

Mr. Sienkiewicz. Well, I believe——

Mr. McNulty. Or any other methods of burning something up.

Mr. Sienkiewicz. I think there are coal-fired plants who have variable costs less than 30 mills per kilowatthour.

Mr. McNulty. Coal-fired.

Mr. Sienkiewicz. Coal-fired, yes.

Mr. McNulty. Mr. Spigal, back to you again on the subject of those lawsuits brought, I think, in Washington courts and ruled on, at least on one occasion, by the Washington Supreme Court. Do you know the litigation of which I speak?

Mr. Spigal. Yes, sir. I think that's generally referred to as Chemical Bank I.

Mr. McNulty. Was Chemical Bank the real party plaintiff? Who was the nominal plaintiff in the action?

Mr. SPIGAL. Chemical Bank was the real party plaintiff, as bond fund trustee for WPPSS 4 and 5 bondholders. Defendants were WPPSS and each of the 88 utilities which were participants in WPPSS 4 and 5.

Mr. McNULTY. Was Bonneville in the proceedings as a friend of the court or in any other way?

Mr. SPIGAL. Not in that case.

Mr. McNULTY. What case? Does that mean that they were in another case?

Mr. SPIGAL. Yes.

Mr. McNULTY. Which one?

Mr. SPIGAL. We are involved in a number of other cases.

Mr. McNULTY. That go to the enforceability of these contracts?

Mr. SPIGAL. Well, there are separate contracts for WPPSS 4 and 5 and separate contracts each for WPPSS 1, 2, and 3. The validity, enforceability of the contracts for WPPSS 1, WPPSS 2, and WPPSS 3 are the subject of litigation, a lawsuit, which has been appealed to the 9th Circuit Court of Appeals, and that's generally referred to as Springfield III.

Mr. McNULTY. OK. But WPPSS 4 and 5? May I ask this final question, Mr. Chairman?

With respect to WPPSS 4 and 5, is that litigation over and beyond any appellate process?

Mr. SPIGAL. With respect to Chemical Bank I, I believe the Chemical Bank has indicated that it will appeal that matter to the U.S. Supreme Court.

Mr. McNULTY. A decision of the Washington Supreme Court holding the contracts unenforceable.

Mr. SPIGAL. Right.

Mr. McNULTY. Thank you.

Mr. WEAVER. The gentleman from Utah.

Mr. MARRIOTT. Mr. Chairman, let me ask what percent of your power base comes from hydro, as compared to nuclear?

Mr. SIENKIEWICZ. Currently, I would say about 90 percent comes from hydro.

Mr. MARRIOTT. And what was the demand for power, what was your overall marketing amount? How many megawatts did you market 10 years ago?

Mr. SIENKIEWICZ. Ten years ago?

Mr. MARRIOTT. What's been the growth in your market over the last 10 years?

Mr. SIENKIEWICZ. I don't have that figure at hand, Congressman. I'd have to provide it. Certainly, in the last 2 years, it's been very flat, if any growth. There was positive growth in the early portion of that timeframe, certainly less than was forecasted. The forecast in the early 1970's began at around 7 percent per year compounded and gradually declined. And as has been noted, our actuals did not measure up to those forecasts. I don't have a cite for you in terms of what the actual growth rate was.

[EDITOR'S NOTE.—In response to Mr. Marriott's question, the Bonneville Power Administration subsequently supplied the following additional information:]

Mr. Sienkiewicz. BPA's firm system load increased from 4,862 average megawatts in operating year 1973 to 6,690 average megawatts in operating year 1982, an average annual rate-of-growth of 3.61 percent. Firm system load declined from operating year 1982 to 1983, to 5,779 average megawatts; as a result, the average rate-of-growth for the 10-year period, operating years 1973-83, was 1.74 percent per year.

BPA's total sales increased from 65.0 million megawatt hours in fiscal year 1973 to 83.1 million megawatt hours in fiscal year 1982, an average annual rate-of-growth of 2.76 percent. Total BPA sales in FY 1983 declined to about 80.8 megawatthours, resulting in the 10-year average rate of growth decreasing to 2.20 percent.

For purposes of comparison, firm system loads for the West Group Area (the geographic region for which integrated power system planning was done prior to the passage of the Regional Conservation and Power Planning Act) increased from 11,321 average megawatts in operating year 1973 to 15,105 average megawatts in operating year 1982, an average annual rate-of-growth of 3.26 percent. Area firm system load declined from operating year 1982 to 1983, to 13,828 average megawatts; as a result, the average rate-of-growth in Area loads for the ten-year period, operating years 1973-83, was 2.02 percent per year.

Mr. **Marriott**. But what is pushing your price demands up? Is it the infusion of nuclear or is it just the overall cost of increases in hydro? And how does that compare with the increases in coal-fired plants?

Mr. **Sienkiewicz**. Well, the most substantive increase in costs that we've been incurring, and it's been happening since 1974, is the fact that the hydro, the energy that we could get, extract, from our hydrosystem was not sufficient to meet the loads within the region. And therefore, we had to turn to alternative forms of generation. And coal and nuclear were the selected forms of generation for the region. And Bonneville, of course, was involved in the three nuclear projects being discussed. And those are predominant contributors to the increases in cost, together with certainly the severe inflationary effects that we incurred in the middle to the late 1970s.

Mr. **Marriott**. Can you answer me, your increase going from 3.17 mills in 1979 to 17 mills today to 26.8 mills is what I think you were turned down on, the 26.8 figure.

Mr. **Sienkiewicz**. No, sir. The FERC approved the power rates on an interim basis. It was a transmission rate, the provision of transmission for the movement of power for other utilities, that they did not approve.

Mr. **Marriott**. OK. How does your combined mixed hydro rate, nuclear hydromix there, compare with coal-fired rates today?

Mr. **Sienkiewicz**. The rate that we are charging the public agencies, I think, which would be most descriptive of the combination of the hydro cost plus those thermal costs which are currently in our system, is 22 mills per kilowatthour. I suspect that that is less than most fully distributed costs of coal-fired generation.

Mr. **Marriott**. One other question. What effect does all of this have in the real world on things in Utah? Can you tell me how this affects the State of Utah?

Mr. **Sienkiewicz**. In terms of the direct rate impact?

Mr. **Marriott**. Yes.

Mr. **Sienkiewicz**. To the extent that Utah may want to avail itself of the opportunity to purchase nonfirm or economy energy from Bonneville, they would be concerned about the increases in the rates for nonfirm energy. They are not a firm power customer and, therefore, they would not be immediately concerned.

[Editor's note.—In response to Mr. Marriott's question, the Bonneville Power Administration subsequently supplied the following additional information:]

AVAILABLE

The transmission capacity (interconnection) between Utah and the PNW is quite small, about 200 MW. The amount of interconnection limits any direct interaction between the two regions. The direct effects on Utah of PNW rates are the same as those to any other connected system. The price of nonfirm and secondary energy determine whether they are attractive resources to displace Utah coal-oil-gas generation. The interconnection limits the capacity that can be transmitted over peak hours. Given the Pacific Northwest surplus combined with the higher cost of Utah resources, it is unlikely that Utah resources would displace PNW resources.

PNW rates could also affect Utah's power situation vis-a-vis arrangements with the PSW. Changes in PNW-PSW intertie capacity, rates, and firm contracts all change the relation of the PSW to Utah as either a potential market or energy diversity/pooled reliability partner. It isn't clear Utah is interested in such arrangements, but such arrangements would be impacted by the operation of the electric system in the Northwest.

Mr. MARRIOTT. If they wanted to buy some power, what would it cost them?

Mr. SIENKIEWICZ. The nonfirm energy rates vary, depending upon the particular marketing circumstance. The base rate is 18.4 mills per kilowatthour.

Mr. MARRIOTT. 18 point what?

Mr. SIENKIEWICZ. 18.4.

Mr. MARRIOTT. Thank you very much, Mr. Chairman.

Mr. WEAVER. Thank you very much. The subject of this hearing, and I think the questioning has been excellent, is what are the financial conditions of Bonneville? Is it going to go insolvent?

The question I'm going to ask Mr. Johnson is why are these costs going up so staggeringly, according to your figures. But, first, I'll just read what the chairman of the Federal Energy Regulatory Commission said yesterday. He said:

"The Bonneville Power Administration is gambling the economy stays strong."

And I'm going to be asking Mr. Johnson, if he doesn't get these revenues, what gets cut?

Mr. MCCAIN. Mr. Chairman, a lot of Republicans are, too.

Mr. WEAVER. Right. [Laughter.]

Yes; the FERC chairman goes on to say: "I would send a message to this blackjack outfit that we're not going to be held hostage to this renegade outfit." Calling the BPA a sacred cow on Capitol Hill, Commissioner Georgiana Sheldon sided with fellow Commissioner Oliver Richards, saying that, if the BPA does not want to be under the Commission, it should go to the Congress and get removed from the Act.

So, Mr. Johnson, in 1979, your costs were $316 million. In 1983, they had jumped to $1.331 billion. What was the largest single factor in that increased cost jump?

Mr. JOHNSON. I'm going to ask Mr. Ailshie.

Mr. WEAVER. Sure.

Mr. JOHNSON. I know you want to go into detail on these numbers, and he can give you informed answers.

Mr. WEAVER. Sure. What's the largest single factor causing that jump from $316 million to $1.331 billion, Mr. Ailshie?

Mr. AILSHIE. Without actually, Mr. Chairman, without actually calculating exactly——

Mr. WEAVER. Let me give you the figures. If you don't have them——

Mr. AILSHIE. It appears——

Mr. WEAVER. The cost of WPPSS was 0 in 1979 and in 1983, it was $633 million. Maybe I'll help you by giving you your own figures.

Mr. AILSHIE. I have the numbers, Mr. Weaver.

The Supply System plants 1, 2, and 3 in 1983 is about $633 million, as you indicated. And the Residential Exchange——

Mr. WEAVER. Now, remember, we're netting Residential Exchange, Mr. Ailshie.

Mr. AILSHIE. The Residential Exchange costs included in the $1.768 billion are $544 million.

Mr. **Weaver**. Mr. Ailshie, I'm going to ask you one final time that the figures I want used are net Residential Exchange. Do you understand?

Mr. **Ailshie**. Yes, sir, I understand. I'm trying to compare the cost numbers that you're quoting with the cost numbers——

Mr. **Weaver**. All right. Well, then, I'll use the net figures. I just didn't want to get you all confused again. $1.331 billion. That nets the Residential Exchange. What is the largest single cost factor increase, Mr. Ailshie? Please tell us.

Mr. **Ailshie**. The Supply System plants are the largest——

Mr. **Weaver**. The cost of the nuclear plants.

Mr. **Ailshie** [continuing]. By about $90 million.

Mr. **Weaver**. The cost of the nuclear plants. Have they produced any electricity yet, Mr. Johnson?

Mr. **Johnson**. No, they have not.

Mr. **Weaver**. Thank you. Now, here's my real question, because what I've just asked you is obvious. My question that puzzles me is that in 1986, 1987, and 1988, your costs keep skyrocketing—$3.6, $4.1, $4.5 billion. We now have a stable WPPSS cost, stabilizing at around, I suppose, $900 million a year, roughly. Why do you show these future costs going up so sharply?

Now I don't know the answer, because you haven't given me any other figures.

Mr. **Ailshie**. The numbers that were prepared for the out-year estimates, for 1986 through 1988-89, as included in our budget estimates, include projections based on the increases in both Residential Exchange, excuse me——

Mr. **Weaver**. That's all right, because you haven't given me those figures. So that is important to know.

Mr. **Ailshie**. And the increased requirements for resource acquisition which were part of our earlier planning estimates. Those are currently being reevaluated in light of the new load growth.

Mr. **Weaver**. I see. They include resource acquisition. So when Mr. Johnson said a few moments ago that he planned to acquire additional thermal capacity, that was what was involved here. Is that correct?

Mr. **Ailshie**. No, sir.

Mr. **Weaver**. I'm sorry. You said resource acquisition.

Mr. **Ailshie**. I said in our category of resource acquisition planning, we had some numbers that went along with higher load growths of a year ago that are now being looked at and readjusted downward to reflect the lower load growths of the current load growth forecast.

Mr. **Weaver**. Very good, Mr. Ailshie. These are old hat figures from way back when you planned additional expansion.

Mr. **Ailshie**. They also include a 7-percent escalation factor.

Mr. **Weaver**. In what?

Mr. **Ailshie**. In each of the years.

Mr. **Weaver**. In what? In what category?

Mr. **Ailshie**. In all categories.

Mr. **Weaver**. All categories? Even WPPSS bond payments?

Mr. **Ailshie**. No, sir. In all categories——

Mr. **Weaver**. Except that.

Mr. Ailshie [continuing]. That are subject to escalation. Well, they probably would not be in Residential Exchange. They would not be in any of the interest or associated project costs or in parts of the BPA program costs. They would be applied to those that would be subject to escalation.

Mr. Weaver. All right. My next round of questioning is going to be: If you don't get your revenues, what are you going to cut? But my time has expired and the gentleman——

Mr. Marriott. Would the gentleman yield?

Mr. Weaver. Well, I don't have time to yield. I really don't.

Mr. Marriott. All right.

Mr. Weaver. I'll ask unanimous consent for 30 additional seconds. [Laughter.]

I yield to the gentleman from Utah.

Mr. Marriott. I want to make sure that I understand what we're getting at here. What is the argument? Is the argument that you should not have built the nuclear powerplants?

Now I'm not sure if I understand where my good friend on my left is coming from.

Mr. Weaver. I say to my friend next to me: We all know that in the Northwest. We shouldn't have built them. That's the argument.

Mr. Marriott. Your increase in cost is due to the fact that you made a capital expenditure for nuclear powerplants that are not yet on line. Is that the bottom line?

Mr. Johnson. That's the bottom line.

Mr. Marriott. And we're now arguing that that's a terrible thing. We should never have built the nuclear powerplants, because we don't need the power. Is that the argument? Can you justify—I mean, is that what we're talking about, Mr. Chairman?

Mr. Weaver. Everybody in the Northwest, except a few—you know, the kinds of people who, like the ones who hold out in the mountains after the war is over—everybody in the Northwest knows that WPPSS was an enormous fiasco, that it's bankrupt——

Mr. Marriott. Well, wait 1 minute, Mr. Chairman. I want to come back and ask this question.

Mr. Weaver. You may have some holdouts over there.

Mr. Marriott. In the State of Utah, Utah Power & Light Co., for example, is trying to get their hands on hydropower because it's so cheap. Their only option is to build very expensive coal-fired plants.

Well, what's so different about that than this? I mean, no one's going to argue that we can build cheaply. Do you have an option to go some place and get more hydropower at lower prices than you can get nuclear power for?

Mr. Johnson. Mr. Congressman, the largest potential of the Columbia River and its tributaries, hydro potential has been developed. So we do not feel that there are major acquisitions that can be made for hydro. However, under the Regional Power Act, assessment and evaluation is being made of smaller hydro opportunities. But they'll be very small in relationship to the total resource capability of the Agency.

So you're correct. There are not significant opportunities remaining in hydro.

Mr. Marriott. But you're building nuclear powerplants today, even though it's a costly venture for the future? Is that the idea? Because you anticipate a greater demand and need for that power 10, 15 years from now? Or did you just build them, was it a mistake to build them in the first place?

Mr. Johnson. Let's go back to the utility planners in the region a number of years ago in the early 1970's, late 1960's, recognized that there was no more hydro to be developed. They saw load growth, so they wisely attempted to plan for that event—namely, to make sure that there was adequate generating capability to meet load growth.

So in connection with that, some coal-fired generation was begun by private utilities, some nuclear generation was begun and completed by the private utilities, successfully. And the Washington Public Power Supply System, primarily for the public agency utilities in the region, commenced to construct nuclear resources. And those are the subject of our discussion today.

Today the issue is how can we wisely manage them with the investments that we have already in place, together with what we expect in the way of future need, to make sure that we make the wisest possible utility choices at this time, given the history we inherit.

Mr. Marriott. And you did not plan the recession, and I assume the recession has a great deal to do with your problems as well.

Mr. Johnson. Well, the recent recession was a matter that impacted our region as well as the rest of the country. And we've had to factor that into some of our decisions, yes. And we've tried to account for that on a sound business-like basis.

Mr. Marriott. So why are we having this hearing?

Mr. Weaver. Because everything he's saying is going to come down in shambles.

Mr. Moody. Mr. Chairman, is the 30 seconds up yet?

Mr. Weaver. The gentleman is on his second round of 5 minutes and his time has now expired.

Mr. Moody. I want to jump in on one of those.

Mr. Marriott. Mr. Chairman, I think, looking at my watch, I have 30 seconds.

Mr. Weaver. Your watch is better than mine. You have 30 seconds. [Laughter.]

Mr. Marriott. Before I yield, are you in the great financial straits that we're being led to believe you are?

Mr. Johnson. I don't believe so. I think that actions have been taken that put us in a sound financial position at this time, and I feel quite confident in that.

Mr. Marriott. Thank you very much. I'd be happy to yield to my friend my last 10 seconds. [Laughter.]

Mr. Weaver. As a matter of fact, I now do recognize the gentleman from Wisconsin for his next round.

Mr. Moody. As a noninformed or barely informed observer, it sounds to me as though it would be fair to say that you overbuilt, or at least the building took place earlier than it might have optimally been done, based on some, frankly, miscalculations about future growth in power demand, based perhaps on expectations on interest rate costs, based perhaps on mistaken projections on economic climate, the recession, and so forth.

So, I mean, without spending the rest of the hearing rubbing salt into the wounds about those mistakes of either building too early or building too much, let's look forward. What are the incremental decisions that we have in front of us?

It seems to me the big one is, of course, when and whether you activate WPPSS 3. How will you rationally make a decision? What are the processes, if you don't mind walking me through it, that you rationally make a decision as to whether or not and, if so, when to open WPPSS 3? Obviously, it's a dynamic programming kind of challenge. You've got future factors to take into account. You've got the economy and its driving demand for electricity. You have elasticity, expected elasticity both in the residential and in the nonresidential sectors, demand that will change. And you have the cost of doing it at one stage in the game versus later. Obviously, those costs are not identical.

So can you walk us through your rational process of deciding whether or not to and when to open WPPSS 3? Maybe the rational outcome is to mothball it for 20 years. Maybe that's not the rational answer. But I'd like to know how you rationally arrive at that basically dynamic decisionmaking programmatic calculus.

Mr. JOHNSON. Looking to the future, first of all, I think it's important to note that in connection with WPPSS 3, Bonneville, in effect, is buying the output for roughly 70 percent of its capacity. The other 30 percent is owned by some four private utilities in the region.

So we'll be working together with them and cooperatively with them in making this decision.

I can assure you that we in Bonneville are not in the business of building any resource just for the fun of it. Resources are built and constructed or acquired, the output is acquired, pure and simply in the most utility-prudent, fiscally sound manner. We acquire resources to meet load.

So within that context and with respect to WPPSS 3, at the present time it is in the state of preservation. Our current forecasts suggest to us that we will need to restart it in 3 years because it is——

[EDITOR'S NOTE.—In response to Mr. Moody's question, the Bonneville Power Administration subsequently supplied the following information:]

Subject: Response to Question by Congressman Moody

Question: How has BPA analyzed the economics of delay versus continued construction of plants such as WNP #3?

Answer: The following text and tables have been extracted from BPA's staff Report titled "WNP-3 Resource Economics and Construction Schedule Update" dated October 26, 1983 to provide an explanation in BPA's Analysis of the economics of WNP-3 delay versus continued construction.

Context of the WNP-3 Restart Evaluation

In April and May of this year, BPA staff examined the system economics, rate impacts, and financial considerations surrounding various courses of action for WNP-3. The findings were documented in the "Analysis of Alternatives Related to WNP-3," May 26, 1983. Since that report, construction ramp-down on WNP-3 has commenced.

Options for construction restart continue to be examined. This report describes the system economics and rate impacts of various restart scenarios.

Actions on WNP-3, not WNP-1 or WNP-2, are the focus of this report. WNP-2 is ready for fuel loading, and previous studies have shown that it is the most economic of the projects to bring on-line as scheduled. Delay of WNP-2 could impose added costs and other problems on the project. For these reasons, WNP-2 is assumed to come on-line in February 1984 in all scenarios. WNP-1 is already in a preservation state and is scheduled for a delay of up to 5 years. No compelling reason to reduce the duration of the delay for WNP-1 has surfaced since the decision to delay was made. Because the scheduled construction restart date for WNP-1 is still several years away, a re-evaluation of the optimal restart date is not necessary now but will be more valuable as current load and resource uncertainties become clearer with time. Accordingly, WNP-1 was assumed to come on-line in June 1991 for this evaluation. The exceptions were the scenarios used to evaluate a delay of more than 3 years for WNP-3. In these scenarios, the on-line date for WNP-1 was also delayed to make the scenarios internally consistent.

Alternatives Considered

The decisions that are likely to be necessary on WNP-3 in the near-term involve: (1) the date of construction restart; (2) the pace of construction after restart; and (3) the source of funding for the net-billed portion of the project.

1. Restart Dates: Restart dates of January 1984, July 1984, July 1985, and July 1987 were evaluated. January 1984 is the very earliest that construction could conceivably be restarted under some Congressional initiative, and according to the Supply System it would yield a minimum 1-year delay in the on-line date to December 1987 if a fast construction pace was pursued, or a 1 1/2-year delay if a slower and more efficient construction pace were pursued. Project activities would not be fully ramped-down at the time of restart. July 1984 is perhaps a more realistic restart date under a Congressional initiative, yielding a 2-year delay in on-line date. Project activities would be fully ramped-down at that

point. A July 1985 restart would yield a 3-year delay in on-line date with a fast construction pace and a 3 1/2-year delay with a slower pace. The July 1987 restart date was considered to test the economics and rate impacts of a 5-year delay in on-line date.

2. Construction Pace: Two construction paces were considered: the maximum pace and a slow, more economic, construction pace. Both paces were defined by the Supply System. Figure 1 depicts these construction paces and how they were associated with restart and on-line dates. Alternatives A, B, and C depict a maximum pace, while alternatives D and F depict a slower pace.

3. Source of Funds: Three sources of funds were considered: (1) conventional bond financing, assuming a 13 percent interest rate and a 35-year term; (2) bank financing through a new financing entity, assuming a 12.5 percent interest rate and a 12-year term; and (3) BPA revenue financing.

Analysis of Risk

Because future loads, interest rates, and the export market can vary significantly, the consequences of each alternative near-term decision on WNP-3 were forecast under a range of load forecasts, interest rates, and marketing assumptions. The consequences of an involuntary termination of WNP-1 and/or WNP-3 were also analyzed. Termination scenarios were analyzed for two reasons: (1) to examine whether alternative resources could be substituted for WNP-1 or WNP-3 at lower system cost; and (2) to estimate the economic and rate impacts of an involuntary termination.

To assess the influence of various risk factors on the economics of alternative decisions, probabilities were assigned to each load growth rate, and expected present values of system costs were computed for alternative decisions. BPA's new low, base, and high load forecasts were used. The probability that actual loads will exceed each forecast is estimated to be 90 percent for the low load forecast, 50 percent for the base forecast, and 10 percent for the high forecast.

All of the scenarios that were evaluated are listed in Table 1.

RESOURCE ECONOMICS

As in previous evaluations, long-term system costs were forecast for each of the WNP-3 restart scenarios shown in table 1. System costs are reported in terms of present values in 1982 dollars, to allow consistent comparisons of scenarios.

Tables 2 and 3 present the economic evaluation results for each restart scenario. In the following pages, some of the most pertinent comparisons between scenarios are made. In these pages, as in the tables, scenarios are compared in terms of present value of 1982 $, in millions. Present values include the life-cycle costs of all resources added over the 20-year study horizon, plus the costs of the resources required to replace the initial resources at the end of their life cycles.

The basic procedures used for this economic evaluation are the same as were used for the May 26 report. ("Analysis of Alternatives Related to WNP-3.") This new evaluation incorporates more recent load forecasts and other new information. It also carries the evaluation of load growth uncertainty a step further and attempts to integrate firm export marketing potentials into the evaluation of WNP-3 restart alternatives. A section explaining the methods and assumptions used in the evaluation follows.

Methods and Assumptions Used to Forecast System Cost Impacts

Total regional net system costs were estimated for each WNP-3 alternative. The general method used to forecast costs was the same as was used for the May 26, 1983, "Analysis of Alternatives Related to WNP-3". To provide a consistent basis for comparing alternatives, system costs were discounted back to present value in 1982 dollars. Because there is a great deal of uncertainty about future load growth rates, forecasts of system cost impacts were made under low, base, and high load growth assumptions. A range of assumptions about financing, export sales, interest rates, and alternative resource supply and costs were also tested. Each category of net system costs was forecasted as described below.

a. WNP-3 Capital Costs. Costs to complete WNP-3 on various schedules were estimated by Supply System staff. Construction cash flows were converted to bond schedules in the alternatives in which bond financing was assumed. The cash flows and resulting present values are shown later in this report. BPA's revenue requirement program was used to estimate nominal streams of capital revenue requirements from the schedules of bond sales. A 13 percent interest rate was assumed for new bond sales if such sales could be made. The interest rate assumption was based on advice from BPA's financial advisor, Wertheim Associates. An 8 percent inflation rate was assumed for capital costs, with a 6 percent general inflation rate. The streams of revenue requirements were discounted back to present value in constant 1982 dollars. Capital cost estimates included increases due to ramping-up and ramping-down expenses, plus site preservation costs.

Because there is considerable uncertainty about the interest rate on eventual bond sales, sensitivity analysis was conducted assuming a 15 percent future interest rate on the net-billed share, with no change in the 6 percent inflation rate.

b. Other Resources' Capital Costs. Delay or termination of WNP-3 would require some resources to be developed earlier. Delay or termination increases the present value of the capital costs of these resources.

Counterbalancing this effect is the reduction in the present value of the cost of the resources that would replace Supply System projects at the end of the Supply System projects' lives, since delay of Supply System projects would cause these replacement resources to be delayed.

Both of these counterbalancing effects on the capital costs of other resources were estimated using the System Analysis Model (SAM). Present values of capital costs were estimated by SAM for each alternative, using the mixes of other resources specified by the least-cost mix model (LCMM). The Supply System projects were assumed to be replaced by other large thermal plants at the end of their useful lives under the base and high load forecasts and by conservation and renewable resources under the low load forecast.

SAM is a model that simulates the operation of the regional power system over a 20-year planning horizon, using a prespecified mix of generating and conservation resources. SAM predicts the production costs (O&M and fuel), capital costs, and export revenues for the regional system, given a particular mix of resources. SAM also forecasts the reliability of the system, in terms of average megawatts of load curtailed.

c. System Production Costs. Production costs are the costs of operating generating resources, including fuel and nonfuel O&M costs, both fixed and variable, and including the production costs of the WNP projects. Delaying WNP-3 projects has two counterbalancing effects on system production costs: delaying the project delays its stream of production costs, thereby reducing their present value; and the absence of generation from WNP projects tends to force other thermal resources to operate more often, thereby increasing their costs. SAM was used to estimate both of these effects on production costs.

d. Secondary Revenues. Delay or termination of WNP projects would reduce the amount of firm power available for export, and hence would reduce revenues from export. SAM was used to predict the magnitude of this loss in revenues. The following assumptions are used in SAM to estimate export revenues:

-- The highest cost resources currently operating are exported.

-- When the intertie is not full, the export price for thermal resources is equal to their fully-allocated costs, up to a ceiling of 30 mills per kWh, and the price for hydro exports is 20 mills (approximately BPA's standard rate). The 30 mill figure is a current estimate of the maximum market price for nonfirm export sales.

-- When the intertie is full, the export price for thermal resources is their incremental cost plus 2 mills, and for hydro the price is 9 mills (representing the spill rate) for energy the system would otherwise spill, and 20 mills for energy which could be stored.

-- At these prices, it is assumed that Pacific Southwest utilities will always be willing to buy power up to the intertie capacity.

Under these assumptions, the export price declines as new increments of firm surplus supply with low or no variable cost are added to the system.

A firm export scenario was also examined. In this scenario, a new 1500 MW firm export was assumed to exist between 1985 and 2000, with a 1500 MW intertie expansion in 1990. A price of 45 mills/kWh was also assumed in this scenario.

e. Curtailment Costs. The analysis suggests that firm deficits can probably be avoided even if WNP-3 undergoes a multiyear delay. Even so, delay of WNP-3 could cause some small increase in the probability of load curtailment, primarily to the interruptible quartile of DSI load. The cost of curtailing interruptible load was set at 22 mills per kWh. There is clearly a great deal of uncertainty and sensitivity about the cost of load curtailment. The value was set roughly equal to the price paid for energy by DSI customers. Arguments can be made for much higher and much lower values. However, it became clear from these SAM studies that use of alternative estimates of the cost of curtailment, within any reasonable range, would not significantly affect the conclusion of the evaluation.

f. Resource Shifts in Response to WNP-3 Schedule Changes. Delay in the construction of WNP-3 is likely to require only minor adjustment in the schedules of new resource additions, assuming the low or base load forecast. Assuming the high forecast, or base loads with a 1500 MW firm export, more significant acceleration of the development of new resources would be required. Likewise, termination of a plant under base loads would require significant acceleration of conservation and renewable resources in the 1990's, and development of additional new thermal capacity around the year 2000. These resource shifts were forecast using BPA's Least Cost Mix Model (LCMM).

TABLE 1

WNP-3 Restart, Scenarios Evaluated

Restart Scenario#	WNP-3 Restart Date	Construction Pace	Financing	Interest Rate[1]	Discount Rate	Load Growth	Surplus Marketing[2]	Conservation in Resource Plan	WNP-3 C.O.	WNP-1 C.O.
A-1	Jan. '84	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '87	June '91
A-2	Jan. '84	Fast	Conventional	15%	3%	Base	N.F.	LCMM	Dec '87	June '91
A-3	Jan. '84	Fast	Conventional	13%	3%	High	N.F.	LCMM	Dec '87	June '91
A-4	Jan. '84	Fast	Conventional	13%	3%	Low	N.F.	LCMM	Dec '87	June '91
A-5	Jan. '84	Fast	Conventional	13%	3%	Base	Firm	LCMM	Dec '87	June '91
A-6	Jan. '84	Fast	Bank	12.5%	3%	Base	N.F.	LCMM	Dec '87	June '91
A-1X	Jan. '84	Fast	Conventional	13%	3%	Base	N.F.	2500	Dec '87	June '91
A-1R	Jan. '84	Fast	Conventional	13%	3%	Base	N.F.	1000	Dec '87	June '91
B-1	July '84	Fast	Bank	12.5%	3%	Base	N.F.	LCMM	Dec '88	June '91
B-2	July '84	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '88	June '91
C-1	July '85	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '89	June '91
C 1a	July '85	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '89	June '93
C-2	July '85	Fast	Conventional	15%	3%	Base	N.F.	LCMM	Dec '89	June '91
C-3	July '85	Fast	Conventional	13%	3%	High	N.F.	LCMM	Dec '89	June '91
C-4	July '85	Fast	Conventional	13%	3%	Low	N.F.	LCMM	Dec '89	June '91
C-5	July '85	Fast	Conventional	13%	3%	Base	Firm	LCMM	Dec '89	June '91
C-6	July '85	Fast	Revenue	NA	3%	Base	N.F.	LCMM	Dec '89	June '91
C-7	July '85	Fast	Conventional	13%	3%	Low	Firm	LCMM	Dec '89	June '91
C-1X	July '85	Fast	Conventional	13%	3%	Base	N.F.	2500	Dec '89	June '91
C-1R	July '85	Fast	Conventional	13%	3%	Base	N.F.	1000	Dec '89	June '91
D-1	July '85	Slow	Revenue[3]	NA	3%	Base	N.F.	LCMM	June '90	June '91
D-2	July '87	Slow	Conventional	13%	3%	Base	N.F.	LCMM	Dec '91	June '95
D-3	July '85	Slow	Conventional	13%	3%	Base	N.F.	LCMM	June '90	June '91

F-1	Jan '84	Slow	Conventional	13%	3%	Base	N.F.	LCMM	June '88	June '91
F-2	Jan '84	Slow	Conventional	13%	3%	High	N.F.	LCMM	June '88	June '91
T-1[4]	July '85	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '89	Out
T-2[4]	July '85	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Out	Out
T-3[4]	July '85	Fast	Conventional	13%	3%	High	N.F.	LCMM	Dec '89	Out
T-4[4]	July '85	Fast	Conventional	13%	3%	High	N.F.	LCMM	Out	Out
T-5[4]	July '85	Fast	Conventional	13%	3%	Low	N.F.	LCMM	Dec '89	Out
T-6[4]	July '85	Fast	Conventional	13%	3%	Low	N.F.	LCMM	Out	Out
T-7[4]	Jan. '84	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '87	Out
T-8	July '85	Fast	Conventional	13%	3%	Low	Firm	LCMM	Dec '89	Out
T-9	July '85	Fast	Conventional	13%	3%	Low	Firm	LCMM	Out	Out
T-10	July '85	Fast	Conventional	13%	3%	Base	Firm	LCMM	Dec '89	Out
T-11	July '85	Fast	Conventional	13%	3%	Base	Firm	LCMM	Out	Out
T-12[4]	July '85	Fast	Conventional	13%	3%	Base	N.F.	LCMM		June '91
T-2X	July '85	Fast	Conventional	13%	3%	Base	N.F.	2500	Out	Out
T-1X	July '85	Fast	Conventional	13%	3%	Base	N.F.	2500	Dec '89	Out
T-2R	July '85	Fast	Conventional	13%	3%	Base	N.F.	1000	Out	Out
T-1R	July '85	Fast	Conventional	13%	3%	Base	N.F.	1000	Dec '89	Out

Footnotes

[1] Interest rates based on DRI forecasts and advice from Wertheim.

[2] N.F. = Non-firm. All of WNP-3's output is treated as secondary by the SAM export sales logic chosen for SAM's study. In the firm export scenarios, a 1500 MW firm export was assumed to be in place, with a 1500 MW expansion in intertie capacity.

[3] In this scenario, part of WNP-3 construction costs are paid out of BPA revenues, and part are financed through conventional bonds.

[4] Subscenarios were evaluated for these termination scenarios. In one subscenario, termination was assumed to occur before restart. In the other subscenario, termination was assumed to occur after construction restart. Results for both subscenarios are shown in Tables 2 and 3.

FIGURE I

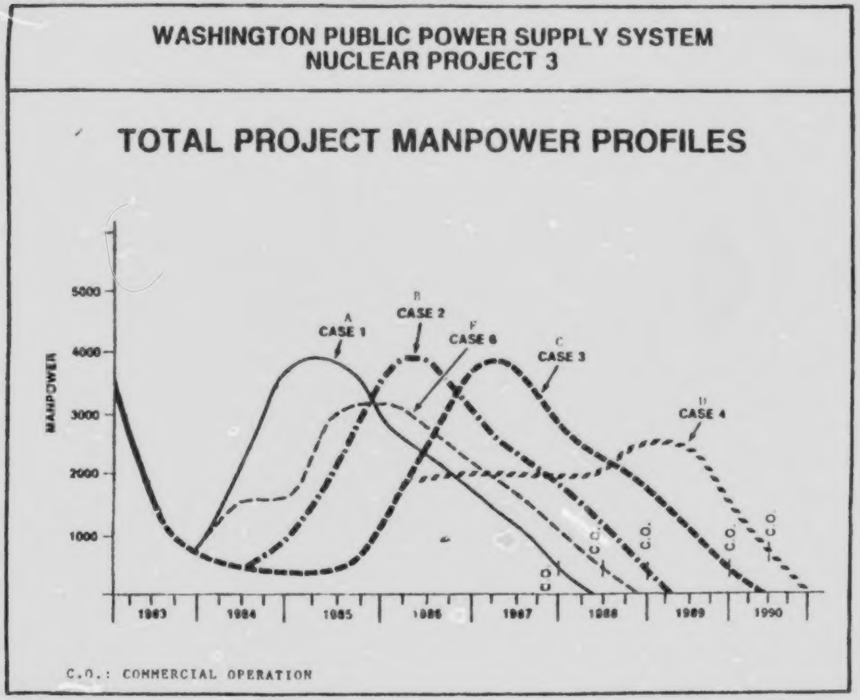
WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT 3
TOTAL PROJECT MANPOWER PROFILES
MANPOWER
5000
4000
3000
2000
1000
A
CASE 1
B
CASE 2
F
CASE 6
C
CASE 3
D
CASE 4
C.O.
C.O.
C.O.
C.O.
C.O.
1983
1984
1985
1986
1987
1988
1989
1990
C.O.: COMMERCIAL OPERATION

TABLE 2

Present Value of Regional Costs
Including WNP Projects (Millions 1982 $)

Alternative:	A1	A2	A3	A4	A5	A6	A1X	A1R	B1	B2
Interest Rate:	13%	15%	13%	13%	13%	12.5%	13%	13%	12.5%	13%
Load Forecast:	Base	Base	High	Low	FM Expt	Base	Base	Base	Base	Base
WNP-3										
Re-start Date	Jan 84	Jan 84	Jan 84	Jan 84	Jan 84	Jan 84	Jan 84	Jan 84	Jul 84	Jul 84
Commercial Oper.	Dec 87	Dec 87	Dec 87	Dec 87	Dec 87	Dec 87	Dec 87	Dec 87	Dec 88	Dec 88
BPA 70%	3147	3335	3147	3147	3147	2786	3147	3147	2907	3285
Sunk	1843	1843	1843	1843	1843	1843	1843	1843	1943	1843
To Complete	1304	1492	1304	1304	1304	943	1304	1304	1064	1442
IOU 30%	909	909	909	909	909	909	909	909	1012	1012
WNP-1										
Commercial Oper.	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91
Total	4674	5001	4674	4674	4674	4674	4674	4674	4674	4674
Sunk	2351	2351	2351	2351	2351	2351	2351	2351	2351	2351
To Complete	2323	2650	2323	2323	2323	2323	2323	2323	2323	2323
WNP-2										
WPPSS Capital Costs	145	145	145	145	145	145	145	145	145	145
Subtotal	4681	5196	4681	4681	4681	4320	4681	4681	4674	4674
All Other Systems Costs										
Capital	27292	27292	56599	14901	30374	27292	27086	27405	27249	27249
Production	32730	32730	55416	28541	33264	32730	31550	33239	32661	32661
Secondary	(10880)	(10880)	(8230)	(12760)	(11125)	(10880)	(10929)	(10980)	(10859)	(10859)
Short-Term Purchase (outside Region)					226					
Curtailments	2023	2023	2336	444	1896	2023	1949	1847	2031	2031
Total Present Value of Regional	55846	56361	110802	38769	59316	55485	54337	56192	55626	56004

TABLE 2 (Continued)

Present Value of Regional Costs
Including the WNP Projects (Millions 1982 $)

Alternative:	C1	C1a	C2	C3	C4	C5	C6	C7	C1X	C1R
Interest Rate:	13%	13%	15%	13%	13%	13%	Revenue	13%	13%	13%
Load Forecast:	Base	Base	Base	High	Low	Base Fm Expt	Base	Low Fm Expt	Base	Base
WNP-3										
Re-start Date	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85
Commercial Oper.	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89
BPA 70%	3273	3273	3466	3273	3273	3273	2761	3273	3273	3273
Sunk	1843	1843	1843	1843	1843	1843	1843	1843	1843	1843
To Complete	1430	1430	1623	1430	1430	1430	918	1430	1430	1430
IOU 30%	1038	1038	1038	1038	1038	1038	1038	1038	1038	1038
WNP-1										
Commercial Oper.	Jun 91	Jun 93	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91
Total	4674	4705	4674	4674	4674	4674	4674	4674	4674	4674
Sunk	2351	2351	2351	2351	2351	2351	2351	2351	2351	2351
To Complete	2323	2354	2650	2323	2323	2323	2323	2323	2323	2323
WNP-2										
WPPSS Capital Costs	145	145	145	145	145	145	145	145	145	145
Subtotal	4936	4967	5456	4936	4936	4936	4424	4936	4936	4936
All Other Systems Costs										
Capital	27185	27070	27186	56477	17713	30158	27186	21193	26970	27277
Production	32617	32496	32617	55503	28385	33120	32617	30269	31424	33112
Secondary	(10837)	(10769)	(10837)	(8178)	(12737)	(11099)	(10837)	(10872)	(10869)	(10926)
Short-Term Purchase (outside Region)						486				
Curtailments	2042	2055	2042	2382	419	1908	2042	1082	1982	1876
Total Present Value of Regional	55944	55819	56464	111120	38716	59609	55432	46608	54443	56275

TABLE 2 (Continued)

Present Value of Regional Costs
Including the WNP Projects (Millions 1982 $)

Alternative:	D1	D2	D3	F1	F2
Interest Rate:	Revenue	13%	13%	13%	13%
Load Forecast:	Base	Base	Base	Base	High
WNP-3					
Re-start Date	Jul 85	Jul 87	Jul 85	Jan 84	Jan 84
Commercial Oper.	Jun 90	Jun 91	Jun 90	Jun 88	Jun 88
BPA 70%	2946	3342	3229	3146	3146
Sunk	1843	1843	1843	1843	1843
To Complete	1103	1499	1386	1303	1303
IOU 30%	989	1088	989	911	911
WNP-1					
Commercial Oper.	Jun 91	Jun 95	Jun 91	Jun 91	Jun 91
Total	4674	4734	4674	4674	4674
Sunk	2351	2351	2351	2351	2351
To Complete	2323	2383	2323	2323	2323
WNP-2					
WPPSS Capital Costs	145	145	145	145	145
Subtotal	4560	5115	4843	4682	4682
All Other Systems Costs					
Capital	27125	27502	27125	27241	56622
Production	32560	32170	32560	32710	55455
Secondary	(10820)	(10772)	(10820))	(10825)	(8260)
Curtailments	2035	2096	2035	2361	2361
TOTAL	55460	56111	55743	55830	110860

TABLE 3
Present Value of Regional System Costs
Including the WPPSS Projects (Millions 1982 $)
Termination Scenarios[1]

	Base Loads WNP-1 Out T1	Base Loads WNP-1&3 Out T2	High Loads WNP-1 Out T3	High Loads WNP-1&3 Out T4	Low Loads WNP-1 Out T5	Low Loads WNP-1&3 Out T6	Base Loads WNP-1 Out T7
All Other System Costs							
Capital	28759	30634	57824	59078	17921	18100	28936
Production	34509	36380	57173	59638	27766	28081	34639
Secondary	(10700)	(10666)	(7461)	(6941)	(11790)	(11553)	(10818)
Curtailments	1952	1954	2489	2232	887	1053	1984
Supply System Capital Costs							
WNP-3		Termination Before Restart					
BPA	1430		1430		1430		1304
IOU	1038		1038		1038		909
Costs with Termination	-	181	-	181	-	181	-
WNP-1	0	0	0	0	0	0	0
WNF-2	145	145	145	145	145	145	145
Total	57133	58628	112638	114268	37397	36007	57099
		Termination After Restart[2]					
WNP-3							
(Costs Through Sept. 88)							
BFA	1430	1098	1430	1098	1430	1098	1304
IOU	1038	797	1038	797	1038	797	909
(Costs through Dec. 88)							
WNP-1	1439	1439	1439	1439	1439	1439	1439
WNP-2	145	145	145	145	145	145	145
Total	58572	61781	114077	117421	38836	39088	58538

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[1] For scenarios T-1 through T-6, it is assumed that a decision has been made to put WNP-3 on a July '85 restart schedule, with an anticipated on-line date of December '89, and that termination occurs before construction is restarted on either project. In T7, it is assumed that WNP-3 is restarted in January '84, and brought on-line in December '87, while WNP-1 is terminated before it is restarted.

[2] Costs through December 1988 are assumed to be incurred on WNP-1 and 3 before they are terminated.

TABLE 3 (Continued)
Present Value of Regional System Costs
Including the WNP Projects (Millions 1982 $)
Termination Scenarios1/

	Firm Export				
	Low Loads WNP-1 Out T8	Low Loads WNP-1&3 Out T9	Base Loads WNP-1 Out T10	Base Loads WNP-1&3 Out T11	Base Loads WNP-3 Out T12
All Other System Costs					
Capital	22662	27198	32128	33410	28713
Production	26839	25186	36444	38628	34464
Secondary	(10626)	(10518)	(11824)	(11715)	(10736)
Curtailments	1390	1435	1915	1979	1924
Supply System Capital Costs	Termination Before Restart				
WNP-3					
BPA	1430		1430		
IOU	1038		1038		
Costs with Termination	--	181	--	181	181
WNP-1	0	0	0	0	2323
WNP-2	145	145	145	145	145
Total	42878	43627	61276	62628	57014
	Termination After Restart2/				
WNP-3 (Costs Through Sept. 88)					
BPA					1098
IOU					797
WNP-1					2323
WNP-2					145
Total					58728

	2500 MW & 1000 MW Conservation			
	Base Loads WNP-1 Out T1X	Base Loads WNP-1&3 Out T2X	Base Loads WNP-1 Out T1R	Base Loads WNP-1&3 Out T2R
All Other System Costs				
Capital	26936	28566	29078	30849
Production	32637	33818	34933	36588
Secondary	10667)	(10738)	(10693)	(10517)
Curtailments	2098	2423	1828	1956
Supply System Capital Costs	Termination Before Restart			
5WNP-3				
BPA	1430		1430	
IOU	1038		1038	
Costs with Termination	-	181	-	181
WNP-1	0	0	0	0
WNP-2	145	145	145	145
Total	53617	54395	57759	59202

Mr. Moody. I understand. I want to know what those forecasts are based on. What is the thinking that justifies that? I'm not interested in the conclusion. You told us that earlier. What are the factors that you're taking into account, and please help me gain confidence that you are on top of those factors.

Mr. Johnson. OK. We can come back, because the forecast, obviously, is the singular most important management tool that we're relying upon. And it obviously has not proven out to be the case, with the benefit of hindsight, based on earlier forecasts and so forth.

Mr. Moody. Forecasts of what?

Mr. Johnson. Forecast of load. In other words, the requirements that would be placed upon the Administrator to meet load.

Mr. Moody. But load is a variable. It's not a fixed. It depends on price and it depends on other things.

Mr. Johnson. Precisely.

Mr. Moody. And the price is one handle under your control.

Mr. Johnson. We, obviously, are very sensitive to the quality of our forecast. We know that looking into the future is an uncertain art. But we feel that we have used the latest state of the art in terms of using every process by which persons do in a position like ourselves, a utility, can predict the future. And I, personally, right now have a great deal of confidence in the forecasting that we are doing, and it has been confirmed, incidentally, Mr. Congressman, by a new entity in the region called the Northwest Power Planning Council.

Mr. Moody. I'm not interested in credentials or appeals to authority. I'm interested in hearing from you what you consider the key factors within those projections and what you have found out to make you sure that opening, as you indicated, is the right thing to do.

Mr. Johnson. I'm going to ask Mr. Sienkiewicz, our power manager, who is responsible for that particular function within the Agency, to expand on your question.

Mr. Moody. Thank you.

Mr. Sienkiewicz. Mr. Congressman, the kind of variables that you have talked about are certainly well known to us. The economic and demographic factors that we have to consider in terms of outyear projections have been looked at with a great deal of variability. That is, some things may go very optimistically, while some things may go very pessimistically.

We have tried to put those together in such a way as to get a band on the uncertainty that we face with respect to future loads. Currently, for example, our long-term forecasts range from a low of 1.3 percent per year to a high of 2.6 percent, with a baseload forecast of about 1.8 percent. That creates after 10 to 15 years a considerable amount of difference that we need to deal with in terms of resource strategies. And we are attempting to do that by virtue of looking at alternative resource developments that, in fact, may be the optimum, given that we do not have certainty with respect to the future.

Mr. Moody. Let me ask several specific points, if I can have a little bit more time.

Looking at the aluminum industry, for example, they are paying on an average of 17 mills per kilowatthour for power in other parts of the country. And I guess you're going to be charging them 26.8 mills; am I right?

Mr. Sienkiewicz. Yes, sir.

Mr. Moody. Well, that's a tremendous differential that you're asking them to pay. Have you factored in the point to which they then say, "No, we're not paying. We're leaving. We're going to relocate. We're going to go elsewhere where power is cheaper."

I mean, have you built in those factors?

Mr. Sienkiewicz. Yes, sir. We are certainly attempting to analyze that and believe that currently we are in a sound position to make those determinations with respect to short-term decisions. We have more to understand with respect to long-term decisions.

Mr. Moody. If I could just finish with a statement—I would be very risk-averse if I were in your shoes, given what has happened. And I would err on the conservative side in these projections.

Thank you, Mr. Chairman.

Mr. Weaver. Thank you very much. I will just comment that Bonneville has instituted a 12 mills per kilowatthour energy charge to DSIs, and the rest is a demand charge. Is that not correct, Mr. Johnson? So that they will be paying, regardless of how much they use, that set amount.

Is that not correct?

Mr. Johnson. We have a contract charge with respect to the rates charged the DSIs in this rate case. I cannot speak to the specific percentage relationship.

Ed, can you expand on that?

Mr. Sienkiewicz. Yes, sir, Mr. Chairman. Not all of that demand charge is collected independent of how much they take. There is a customer charge of $7.34 per kilowatt per month. That is a function of the projected demands that we have in a rate case, and they pay that whether or not they take that amount of power. But the rest of it is a function of how much they take, both demand and energy.

Mr. Weaver. Right. In other words, you reduced their energy charge from 23.57 mills to 12.06 mills and instituted a new standard charge. Is that not correct?

Mr. Sienkiewicz. Basically, yes, sir.

Mr. Weaver. Customer charge.

Mr. Sienkiewicz. Customer charge, that's right.

Mr. Weaver. So they will pay that customer charge regardless of how much they use. Is that correct?

Mr. Sienkiewicz. They will pay that charge down to 90 percent of how much we projected for them in a rate case.

Mr. Weaver. Exactly. We'll be getting into a line of questioning on that later.

The gentleman from Arizona.

Mr. McCain. In line with the questioning of my colleague from Wisconsin, the GAO report stated for the past 10 years Bonneville has overestimated electricity sales. Is that true?

Mr. Johnson. Yes.

Mr. McCain. Then I would certainly agree with my colleague from Wisconsin and maybe you might try to err on the other side here to break that record of 10 years of overestimation.

Mr. Chairman, I would like to, first of all, say that I think your statements, particularly the one pointing out the statements that you made 6 years ago as far as the dangers that lay ahead for this project, are extremely valuable. It's not very often, I guess, one can have as a matter of public record such accurate predictions. I think it's important to this committee, and particularly to the newer members, to have had that background information.

I also would hope that we could focus, and I would like Mr. Johnson's comments on this, on this business of a fixed schedule for repaying. I feel that it could clear up a tremendous amount of confusion, of misconceptions on the part of the public so that we can find out whether BPA is going to remain solvent or not. Because, if we have a fixed schedule for repayment with some contingency into it, we could then have a clear idea of how much is going to be required.

From my understanding of what we have discussed this morning, that is not clear at this time. And Mr. Johnson, I'd be glad to hear your comments, and I have no questions after that.

Mr. Johnson. I think I'm repeating a little bit, Congressman, what I may have said before, so bear with me if I do. But under the current methodology, which has not met the test in the last 10 years because of a number of reasons, some of which we've touched on, I, nevertheless, believe at this time in this rate case that we have taken the actions necessary to make that methodology work in order to maintain our responsibilities and honor our obligations to the U.S. Treasury, interest and principal, as well as picking up the deferral of interest payments that have been passed.

I feel confident in that.

I'm also sensitive, however, to your concerns and those, too, of others in the administration as well as the Congress as to whether or not maybe a better way could be found. And we certainly will be cooperative with the Congress in attempting to assess other alternatives that might deliver a more predictable or a better result. At this time, under the law that has been passed by the Congress, we are administering it in a fashion that will work. And I feel that very confidently.

Mr. Weaver. Well, I want to thank the gentleman from Arizona very much, because he began with precisely the line of questioning that I had intended to take up. He asked my first two questions. And if the gentleman from Idaho will forgive me, I'll go out of turn and recognize him later, to continue this very line of questioning.

The General Accounting Office has said that Bonneville has estimated its load growth incorrectly by 8.5 percent, as the gentleman from Arizona said and Mr. Johnson agreed. My point is that now we have the largest single revenue increase to cover their costs. The question I'm going to ask is, if they once again misestimated, and one would think so, because now they've got the biggest increase they've ever had and have consistently misestimated in the past, what they will be cutting.

But, first, I want to go over the details of your revenue increases, Mr. Johnson. I see that BPA plans to collect $839 million from the publicly owned utilities during fiscal year 1984, which is a 32-percent increase of revenues from the $634 million you received during fiscal year 1983.

Why do you think that BPA can increase its take from these utilities by 32-percent in 1 year?

Mr. SIENKIEWICZ. Mr. Chairman, I don't have an immediate table to verify or to correspond to those numbers.

Mr. WEAVER. Those are your figures.

Mr. SIENKIEWICZ. There are several things that are certainly going on. One is that the actuals from which we just left represents a year in which we had much warmer than normal temperatures in the region.

Second, we had a circumstance in which, because of the abundant availability of economy energy that was coming out of the region and competing for market in California, that a number of the public agencies generating utilities were given an economic incentive to displace their take from Bonneville and, in fact, use nonfirm and other purchases in their own load.

We believe that both with the change in the economic condition and the marketing conditions for nonfirm this coming year, as well as with the rate change that we made, that that will be curtailed.

And second, of course, there is some normal load growth that we would expect to occur a little bit higher than a long-term average, because we're coming out of a recession year.

Mr. WEAVER. All right. We will be getting into that rate question later. I don't want to interrupt this line of questioning. You're saying you're going to be charging the public utilities for their own electricity, in effect. But we'll get into that later.

Now BPA also plans to raise $607 million from sales to the DSIs during fiscal year 1984, up from $420 million in fiscal year 1983. Will BPA be able to obtain this 45 percent additional revenue if it again offers the DSI's a fire sale rate later in the year?

Mr. SIENKIEWICZ. Yes, sir; we believe we can.

Mr. WEAVER. You mean you will be offering a fire sale rate later in the year?

Mr. SIENKIEWICZ. No, sir; we're not going to be offering a fire sale. I'm sorry. I misunderstood the question.

Mr. WEAVER. Does Mr. Johnson agree that you will not be offering this lower rate to the DSIs?

Mr. JOHNSON. It was a sale of nonfirm energy because of extraordinary circumstances prevailing in 1983. We do not see that at this time in the 1984–85 period.

Mr. WEAVER. Do you anticipate in further years out that you might offer this fire sale rate?

Mr. JOHNSON. That sale of nonfirm to the DSIs was a special, extraordinary, I hope, nonrecurring circumstance. We also made nonfirm available to our pump irrigation customers, as you know.

Mr. WEAVER. Yes.

Mr. JOHNSON. And, hopefully, we were able to use wisely our resources to assist in the stimulation of our economy. But I would hope that we don't have to visit that again. However——

Mr. WEAVER. I'm not arguing with that decision at all, Mr. Johnson. I just wondered if you were going to make it available.

So you simply think that the DSIs will, and aluminum prices are strong, will continue to use the maximum amount of electricity, and your revenues will go up.

BPA also expects to collect more from California, up from $178 million in fiscal year 1983 to $298 million in fiscal year 1984 and $390 million in fiscal year 1985, an increase of 120 percent in 2 years, even though the Pacific Intertie carried almost as much energy as it possibly could during fiscal year 1983. How is BPA going to get that much more money from California without selling California much more power?

Mr. SIENKIEWICZ. Again, one of the conditions that occurred last year was the large amount of surplus power that was available throughout the year. The prices for sales to California were considerably below what the expectations of Northwest utilities, including Bonneville, were. For example, at this time last year, sales were not going at the 20 to 30 mill per kilowatthour rate at which they are currently being made.

It's our expectation that the average rate for sales out of the Northwest to California will be higher this year than it was during the conditions that we had last year.

Mr. WEAVER. Is the Pacific Intertie full now?

Mr. SIENKIEWICZ. The Intertie is not full. There is maintenance currently occurring on a DC tie, and there is a limited amount of transactions on the AC. That's less than full, in part, because there is not nonfirm energy available and because the loads have increased some in the region, so that there is not the abundant surplus that we are seeing in the last operating year.

Mr. WEAVER. Mr. Johnson, one general question on this subject. Is it reasonable to expect people and businesses to consume more BPA power with this increase in rates that you're imposing? Don't you expect a little elasticity?

Mr. JOHNSON. I think that we factored into our load forecast the elasticity effect. We do believe that, with this rate increase, that there will be increased revenues to the agency.

If you would like more explanation as to how and in what fashion the elasticity factor was applied to our load expectations, I'd be happy to have Mr. Sienkiewicz expand on that.

Mr. WEAVER. Yes, please.

Mr. SIENKIEWICZ. Well, if we look just at the DSI loads, Mr. Chairman, we have a circumstance in which we are projecting for this coming year something in the neighborhood of 2,700 average megawatts sale throughout the year. Last year, that number was closer to 2,000. This is now getting the DSIs back at full capacity. We have had previous years in which we have operated at about 3,000 average megawatts.

So we have made this specific short-term projection based upon our expectation principally of what's going to occur in the aluminum markets and the prices for aluminum. Frankly, we are tracking, at least at the moment, we are tracking that fairly well. Our actuals now are in fact above the expectation which we had in the rate case.

Mr. WEAVER. Well, I hope you succeed, of course. But my next line of questioning will be, if you do not succeed, and I seriously question you will—it flies in the face of everything I know about business and demand—then what costs you will cut if your revenues don't meet these needs, these expectations.

But my time has expired. The gentleman from Idaho's turn is now.

Mr. **Craig**. Thank you very much, Mr. Chairman. I'm going to kind of pick up on your line of questioning because of concerns that I have and that are being expressed to me by customers in the region and certainly in my State as to these costs.

Mr. Johnson, you mentioned, prior to my having to leave the committee for a period, that over a 6-year period, the DSIs had experienced approximately 1,000 percent increase in charges.

Can you tell us in that same timeframe approximately what preference utilities and, oh, Residential Exchange customers, what kind of increase they have experienced during that timeframe, the percentage increase?

Mr. **Johnson**. Modestly less than that. They have gone from roughly the same base, because the industrial rate and the preference and priority rate were very nearly the same in those earlier years, to a figure today of 22 mills as compared to the 26.8 mills for the DSIs. I'm going to roughly estimate that that is in the range of a 700- to 800-percent increase, but I could be inaccurate a little bit on that.

Mr. **Craig**. Well, that sounds approximately right compared to your figures. How do these rate increases compare with private utility rate increases to similar customers in the region, in percentages, not in actual costs or charges, but in percentages of increase?

Mr. **Johnson**. It varies by the private utilities in the region.

Mr. **Craig**. But is there not a regional average?

Mr. **Johnson**. I am not aware of there being a regional average, and I think it would be difficult, Congressman, to compute without making a number of observations with respect to it.

For instance, Bonneville's preference and priority customers for a longer period than the private utilities were able to enjoy the low costs of the hydrosystem.

Mr. **Craig**. I understand.

Mr. **Johnson**. But beginning in the late 1960's, early 1970's, the private utilities, being unable to continue to draw power from Bonneville, set out to expand their resource base and acquire thermal resources. So their rates began to rise earlier than those of the Federal Base System, those of Bonneville. And they rose, I am told, rapidly during that period, coming from roughly the same base. At the present time, on an average, the investor-owned utility rates are higher than those of the Bonneville preference and priority rate. But that depends on each utility. You have to compare that on a utility-by-utility basis.

For instance, Idaho Power Co. rates right now, I believe, are very close to the same as the Bonneville rate.

Mr. **Craig**. So you are not able to respond in at least a timeframe-type answer of 1977–83 average increases. I understand the variables. I think you've explained them thoroughly. But those figures don't exist, to your knowledge?

Mr. **Johnson**. Well, let's make a comparison going back to the day when they could buy power from Bonneville. I would judge that from that time, their rates have increased until today they are more than those of the Federal Base System. And that's the reason for the Exchange. The Exchange still nets back to them——

Mr. CRAIG. I understand that.

Mr. JOHNSON [continuing]. An amount which allows them, then, to pass that savings back to their domestic and rural customers and bring parity among the customers of publicly owned agencies as well as privately owned utilities.

Mr. CRAIG. I know the frustration you had when you took office as it relates to projections and, of course, Bonneville's ultimate involvement with WPPSS 1, 2, and 3, based on projections that we were looking at in the 1960's and the 1970's, versus your concern for accurate projections today. And I think that all of us are very concerned about that.

I also can accept an inability to project the depth of a recession and the kind of shutdowns that would ultimately occur as a result of that and a drop in power demand.

It's the elasticity factor that the chairman talks about. What are you calculating now as a factor as it relates to conservation on the part of preference and exchange type customers as prices go up. Other industries, and especially the gas industry, the natural gas industry, I know in talking with them, they have seen some rather startling figures. Intermountain Gas in Idaho, I think, has experienced something like a 25-percent decrease on an individual customer basis, on an average, of use as price over time moved up. There was a concerted effort to conserve, obviously to save money.

What are the factors you use and how do they project into this revenue base that you're talking about today as you move your prices up to offset your expenses and all of the other kinds of things that are going on inside the system? And what do you expect to be a conserving figure or the elasticity involved?

Mr. SIENKIEWICZ. I'm not sure that I have a number, Mr. Congressman, which would describe precisely what the conservation effect is relative to the changes in price. We have talked about the price elasticity for the various components, and with respect to the aluminum companies, of course, that's very much dependent upon the price of aluminum. And, as I said earlier, we have more information about near term than long term.

[EDITOR'S NOTE.—In response to Mr. Craig's question, the Bonneville Power Administration subsequently supplied the following additional information:]

The price elasticity in the near term is about −0.2. This number has been documented in the Load and Resources Study, September 1983, prepared as part of the 1983 Final Rate proposal. The long-term price elasticity in our demand models is about −0.6. On top of the price response, the load forecast also reflect a reduction in loads due to consumers' participation in BPA and utility conservation programs.

Mr. SIENKIEWICZ. With respect to, I think, focusing on the results, looking at the prices that we had in the region in the early 1970's, if they had prevailed, the long-term load growth forecasts which we had then approaching 7 percent might also have prevailed. But we didn't get that kind of growth, in large part, we believe, because of the price increases. We now have the effects of those price increases incorporated on a prospective basis into our future load projections, such that our base case long-term forecast is now 1.8 percent. That's a significant reduction. That does reflect, in fact, the expectation that folks will consume less electricity because they'll use less or will convert to alternative forms of energy.

Mr. CRAIG. 1.8 percent.

Mr. SIENKIEWICZ. That's the long-term forecast for regional load growth.

Mr. WEAVER. Would the gentleman yield?

Mr. CRAIG. Yes.

Mr. WEAVER. Isn't that 1.8 percent an increase from 1.6 percent? That's what we've been told.

Mr. SIENKIEWICZ. The percentage increase is, Mr. Chairman. Actually, in our forecast now for the 20-year period, our expectation is a decline in loads of about 940 average megawatts some 20 years out, compared to the old forecast. But because of the base change from last year's forecast—the 1983 loads were lower than the base used in last year's forecast—the compound effect to indicate a percentage increase.

Mr. WEAVER. The gentleman's time has expired.

Mr. CRAIG. Thank you, Mr. Chairman.

Mr. WEAVER. We'll have one more question and then we're going to break for lunch and come back at 1:30.

The gentleman from Wisconsin.

Mr. MOODY. I just wanted to make a couple of points. One is that I'm deeply troubled that men of your caliber and responsibility can't come in here and give us, obviously, some numbers that we're going to be asking for—namely, elasticity figures. You said that you can't give me that. We don't have that. We can't give you that. I can't think of any number that is more important to you avoiding catastrophe than to know the elasticity of demand of your major components of the demand.

So that's a comment, Mr. Chairman. It seems the witnesses are unprepared.

Mr. SIENKIEWICZ. I did give you a number for the residential for the near term. I can indicate to you that the range for our short-term retail sales forecast is from minus 0.25 to minus 0.4. And for the long term, it's from minus 0.35 to minus 0.6.

Mr. MOODY. When I asked you about aluminum, though, you didn't have the numbers. That's a very important component.

Mr. SIENKIEWICZ. Sir, we don't believe that, in fact, the forecasting we're doing for the aluminum need be subject to the generalities of elasticity forecasts. We have a very specific model for forecasting the loads of the aluminum companies, and we need not be dependent upon the expectation of general price responsiveness or demand responsiveness to price.

Mr. MOODY. Well, any model that doesn't include elasticity of demand is not worth much.

Mr. SIENKIEWICZ. It includes it, sir, by virtue of looking at what we would expect the individual actions of individual plant owners to be by virtue of changes in electricity prices.

Mr. MOODY. Well, that's elasticity by another name.

Mr. SIENKIEWICZ. We haven't measured that as an elasticity effect, although it is clearly in the forecasting technique.

Mr. CRAIG. Would the gentleman yield?

Mr. MOODY. Certainly.

Mr. CRAIG. Because that's an area that concerns me, and I can appreciate a bit of a difference in being able to project there. Let's say, taking outside the market and market movements and the movement of the economy and if, in fact, by pricing our DSIs into this situation, they have become swing-type industries in the region, at what point are you able or do you attempt to factor in as prices move up, energy costs, that there are or that the industry can and would move in an area of some degree of internal change from the standpoint of conservation based on modernization?

Is that possible in this particular industry? If it is, do you ask those questions? Are they projected in? At 26 or 27 or 28 mills, do we finally get to a point where the Mead plant in Spokane does certain other kinds of things to stay in business Not because the economy is bad; let's assume it's very good. But, at the same time, they can operate more efficiently and, as a result, they're going to change some procedures and/or engineering and/or plant situation.

Is that a factor in your considerations?

Mr. SIENKIEWICZ. Yes, sir.

Mr. MOODY. If I could reclaim?

Mr. CRAIG. Yes, surely.

Mr. MOODY. I may need a little extra time to finish, if I could.

In any event, please supply for the record at your leisure what those exact calculations are for elasticity for your major components. I would appreciate reading it later.

Now, the major concept that I want to share with you or discuss with you is this question of demand management. We have been talking today as though demand were some kind of fixed entity. Actually, the Wisconsin utilities, which I'm familiar with, have done a great deal with peakload pricing and others things to manage demand. You can alter the demand curve. It isn't a fixed item out there. It's alterable by you, depending on all sorts of things.

I guess the classic cliche is that utilities in the 1950's and 1960's didn't think in those terms, and they just projected out as though everything was going to be the same price and you just had a shifting, a rightward shifting demand curve.

But we know now that demand is manageable to a certain extent, either long term through conservation or short term through price structures and price regimes, such as peakload pricing. And often you can avoid a lot of capital expenditures by shifting peaks or by smoothing peaks and by encouraging conservation.

So the answer is not just to go out and build. Frequently, it's to manage demand, the other side of the equation.

What are you doing for demand management?

Mr. SIENKIEWICZ. To date, Mr. Congressman, our focus for some period of years, unlike the rest of the country, has not been with respect to concerns for capacity, but rather, with respect to concerns for energy. We have been an energy-deficit system while, in fact, we have had surpluses in capacity because of the hydrosystem. We have been able to install additional elements to meet our peak needs in a hydrosystem by installing additional units in hydrogenerating projects that will, in fact, provide our peak need, but because the same amount of water is coming down a river, it doesn't add to the energy supply.

We have been an energy-deficit system, and a focus of most of our resource planning has been on meeting our long-term energy need.

Mr. Moody. Mr. Chairman, could I have unanimous consent to finish up?

So you're telling me no, you don't do it. You look at energy need. You don't look at demand curves; you look at energy need, which is a fundamentally different concept. Is that right?

Mr. Sienkiewicz. Our focus has been on a forecast of energy rather than capacity, because we have not been capacity constrained. That is a different phenomenon than is being experienced in the rest of the country, because in order to get their energy, they have to put capacity in in order to do it.

Mr. Moody. Well, for Wisconsin, they need peak capacity with oil or something like that, which has high variable costs but lower fixed costs. And they only turn it on for those peak needs. But then they shift peak to minimize that effect by different pricing structures.

Do you have different prices for different times of day? Do you have peakload pricing?

Mr. Sienkiewicz. We do have peakload pricing and we have seasonal variations in our prices as well.

Mr. Moody. Thank you.

Mr. Weaver. Very modest.

Mr. Moody. Very modest. Well, ours are not modest, and they've had a tremendous cost saving for us in Wisconsin.

Mr. Weaver. I've been trying to get them to do this now again for 10 years and, again, it's impossible.

If you don't raise this money, what are you going to cut? The BPA's outstanding debt to the U.S. Treasury—this is not WPPSS, now; this is the BPA's debt on the old dams, et cetera, to the U.S. Treasury—is about $8 billion. The principal that has been repaid on this obligation since BPA began paying off the WPPSS bonds in 1979 is less than $3 million over 5 years. And now, BPA plans to repay in fiscal year 1984, only $5 million on principal.

Are all those facts correct, Mr. Johnson? They are from your records, but I just want you to substantiate it.

Mr. Johnson. Steve, can you verify these numbers? If they're from our records, then we stand by what we submitted.

Mr. Weaver. Well, but I want you to say it. Mr. Ailshie. Are those facts correct? Your $8 billion, you're going to pay around $5 million on principal in fiscal year 1984.

Mr. Ailshie. The $5 million was the number that was in one of our rate filings. Of course, the final rate filing was slightly different than that. But it's close enough.

Mr. Weaver. Very good. That's exactly the answer I wanted. Now, if you do not meet this enormous increase in revenues, this historical high increase in revenues that you have projected, Mr. Johnson, what will you cut? Will you cut the principal payment or the interest payments due to the U.S. Treasury first?

Mr. Johnson. Looking into the future, obviously, we're expecting that there is going to be load growth. We will require additional resources to meet that load. And so those are costs in our out-years, expected costs in our out-years.

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So, if the load growth does not occur, in other words, if revenues do not increase through the sale of our kilowatthours, our energy, then, we would cut the costs of those resources. In other words, we'd eliminate the need to acquire resources to meet load, because I'd obviously be able to do that and meet my utility responsibilities.

The other area where it is ongoing is increasing the efficiency within our system. We're making a review, for instance, of our transmission reliability and to make sure that we are, in fact, exercising prudent utility practice in keeping costs at the lowest possible level there.

That's ongoing at the present time, which will be a cost savings. In any event, all of these are designed to keep rate and rate increases down.

Mr. **Weaver**. How many in fiscal year 1984? My counsel says that you're talking about fiscal year 1985 costs. So I want to question you on fiscal year 1984 first. What would you cut in fiscal year 1984 payments? If you have a $300 million shortfall, Mr. Johnson, where will it come from?

Mr. **Johnson**. Obviously, I'm going to look anywhere, any item in the budget where I could cut.

Mr. **Weaver**. Yes; what would those be, please, sir?

Mr. **Johnson**. Well, again, I think that we have certain expenditures this next year for conservation in our expenditures.

Mr. **Weaver**. $120 million, roughly, as I recall. So you would cut conservation first?

Mr. **Johnson**. No; we would take a hard look at that, Congressman. We can only make decisions year to year.

Mr. **Weaver**. All right. I just want to know.

Mr. **Johnson**. And we take a hard look at that, as well as all other costs of the Agency. Any place where we could reduce——

Mr. **Weaver**. We'll be having a hearing tomorrow on conservation, as well as WPPSS 3, and we'll go into that then.

What, then, would you cut?

Mr. **Johnson**. I said I would review that.

Mr. **Weaver**. Conservation would be the first cut. I expected that, Mr. Johnson, so it's not a surprise to me. What would be next cut?

Mr. **Johnson**. Obviously, we'd enter once again the deferral of payments to the U.S. Treasury.

Mr. **Weaver**. You would defer payments to the U.S. Treasury. That's $236 million in deferred interest and the $362 million of interest for fiscal year 1984.

That would probably get you through. You probably wouldn't have to cut anything more. That's an enormous amount of money. So that answers my question.

Mr. Johnson, we hope you can stay over. We'll be coming back at 1:30.

Mr. **Craig**. Mr. Chairman.

Mr. **Weaver**. Yes?

Mr. **Craig**. Could I have just one brief response?

Mr. **Weaver**. Surely.

Mr. **Craig**. If there's anything I resent in any committee, it's the committee putting words in somebody's mouth.

Mr. Johnson, when you mentioned conservation just now, did you mention it as one of an area of consideration or a first consideration in priority as it would relate to cuts that might need to be made if you had a revenue shortfall?

Mr. JOHNSON. I appreciate the chance to explain that further. I said that I would look to the reduction in costs in the area of acquisition of resources, if they were clearly not needed.

Mr. CRAIG. Would you——

Mr. JOHNSON. And among that would be conservation. But there might be others, too. I think we have some minimum expenditures for hydro and some research and development expenditures to develop new cogeneration technology. I would take a look at all of those, and that would be my first line of attack, as well as seeking to improve efficiencies within the Agency.

Then it would be after that, obviously, if I had the revenue shortfall that the Congressman asked me to assume would occur, then we would be forced to defer payments to the Treasury.

Mr. CRAIG. Maybe you could submit for the record a list of those areas that you would examine. And I would suggest that you submit them in a circular pattern with a circle in the center that says, a possible decisionmaking activity, so that there would be no possibility of construing that because something became number one or number two or number three on a list of decision areas, that they would be prioritized in anyone's mind.

Mr. WEAVER. I wouldn't want the gentleman from Idaho to be putting words in the witness's mouth. [Laughter.]

Mr. CRAIG. Oh, I'm not, Mr. Chairman. Thank you.

Mr. JOHNSON. We'd be happy to submit some response as to how we would proceed in the decisionmaking process and evaluation of alternatives.

It's a dynamic process, necessarily.

[EDITOR'S NOTE.—In response to Mr. Craig's question, the Bonneville Power Administration subsequently supplied the following information:]

Without knowing the size and cause of the BPA revenue shortfall, it is difficult to anticipate what our response might be. For example, if the shortfall were the result of decreased loads, we would definitely look at cutting costs through reducing the acquisition of resources not needed to meet those loads. Since it is unrealistic to hypothesize as to exactly what we would cut, I will describe the general approach we would take in evaluating alternatives.

All program managers would be asked to identify economies. All discretionary costs would be examined for potential elimination or deferral into a later period.

We would take a look at the level and pace of our conservation program, new acquisitions, and research and development activities to develop new resource technology, in light of the commitment we have made to the region to develop conservation and alternative energy capability to meet longer-term needs.

As I mentioned to the Committee, we are currently reviewing our transmission reliability standards to be sure that we are constructing and operating the system at the most cost-effective level consistent with prudent utility practice. Our transmission construction schedule would also be reviewed, in light of loads and marketing commitments, to see whether any delays—and consequent deferral of costs into a later period—would be possible.

If program economies, elimination of costs for unnecessary resources, and prudent program slow-downs did not accomplish savings to match the hypothetical short-fall, our policy for determining priorities in applying revenues would dictate that the amortization of the Federal investment financed through appropriations be the next place to look for deferral.

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Mr. Craig. It is a dynamic process, and I think the chairman's absolutely correct when he says, "If you have shortfall." We're hoping you don't. But if you do have shortfall, where are you going to cut? What would be the process you would go into, and what would be the areas of consideration to try to get your financial house to maintain its order?

Mr. Johnson. I think that it would be appropriate to reflect on the last 2 years and see precisely what we've done under these circumstances. We have reviewed conservation and we have cut our expenditure rate in half, but not jeopardizing the development of the capability to acquire conservation.

I slowed down WPPSS 1, reducing upward pressures on rates. We have improved efficiency within the Agency. I have cut our transmission expenditures in half. So that's exactly the same process through which we would go again.

Mr. Craig. Thank you.

Mr. Weaver. All right. Before we recess for lunch, we'll take 1 minute. The gentleman from Wisconsin.

Mr. Moody. Are you saying that you wouldn't consider deferring WPPSS 3 as part of this response to shortfall in revenue?

Mr. Johnson. It's deferred now.

Mr. Moody. Would you continue to push it back?

Mr. Johnson. I think that that would be a consideration that would be given serious review.

Mr. Moody. You'd have to make a determination if incremental cost were more than outweighed by incremental revenues of opening it up, wouldn't you?

I mean, that would be the intelligent way of analyzing it. I assume you would agree.

Mr. Johnson. I think that we'd have to look at the entire resource mix alternatives that would be available to us and have to make the decision in the best interest of the region over time.

Mr. Moody. I'm looking for principle. I must say that these generalities and cliches are just driving me nuts—"We would look at the overall." Let's get right down to the way of thinking about a problem.

Mr. Weaver. If the gentleman would yield. I have been going through this for 10 years.

Mr. Moody. Well, I'm new to this, and I haven't ever heard you before. But these phrases don't mean anything—"best possible." I mean, we hear that from so many people and it doesn't mean anything unless you back it up with some hard, crisp concepts.

Isn't it logical to say that the decision on that big ticket item would be balanced against the incremental revenue of opening it up versus the incremental additional cost of opening up? If you're in a cash bind, you've got to think that way, I assume.

Can I get a yes or no, or maybe I'm off base here.

Mr. Johnson. Certainly, that becomes a factor. And I don't want to appear devious. This is a very complex method by which decisions are made in determining what resources should appropriately be acquired to meet load.

And I think that, again, this is not to be general or to be devious or to try to mislead you in my response, but we have a number of options that we can avail ourselves of to meet the loads that the

Administrator would be expected to meet. But let's say that there are no loads. Therefore, it would be moot, obviously, if there are not additional requirements. We'd have to then look at the potential for selling generation outside the region on a firm power basis, and then, of course, we'd be looking to marginal revenues versus marginal costs. But that would not be the only consideration.

Mr. Moody. No. But that would have to be a very powerful consideration on WPPSS 3. I don't know what could possibly be overweighing that. If you're in a cash bind, you're going to have to look at that.

Mr. Weaver. The gentleman, though his questioning is excellent and I commend him strongly for it, his time has expired.

We're going to recess now for lunch and come back at 1:30. We'd appreciate your coming back with your people, Mr. Johnson.

Thank you very much.

[Whereupon, at 12:40 p.m., the subcommittee recessed, to reconvene at 1:30 p.m. of the same day.]

AFTER RECESS

Mr. Weaver. The subcommittee will be in session.

Thank you very much, Mr. Johnson, and your people for staying with us. I'm sorry. We had hoped to have had you go out earlier, and we'll be as speedy as we can.

Mr. Johnson, if BPA's projected rates are multiplied by BPA's expected loads, does this result equal BPA's revenue requirements as set forth in your June 22 budget submittal?

Let me tell you what we have.

Mr. Johnson. Yes, I think it would be beneficial to both of us. We get a certain budget submittal as of a certain time and I immediately can't draw that up in my mind and see the detail of it.

Certainly the rates that we've set, it is my strong belief, are going to be adequate to cover our costs in this rate case, which should be reflected in the budgets. However, we've been living in a dynamic period. There have been changes and they may not all be reflected yet in budget submittals.

I'm not trying to be devious. Let's, if you can, be as specific as you can, and we'll try to answer as accurately as we can.

Mr. Weaver. Well, here's the figures that we have. The figures from your budget show estimated revenues in fiscal year 1984 of $2.825 billion. But if you take, as someone has done, the rates that you have set times the sales you project, in fiscal year 1984, you get $2.265, or $560 million less. In fiscal year 1985, you have $2.912 billion in your budget but get only $2.520 billion from projected sales.

We were wondering where the discrepancy is?

Mr. Johnson. Could I ask this question, which might help us in responding? I know a certain Jim Lazar——

Mr. Weaver Yes, these are his figures.

Mr. Johnson [continuing]. Has prepared some data from information that has been, I believe, published by the agency. And he has developed a document in connection with that analysis.

Mr. Weaver. Right.

Mr. Johnson. We believe that he has overlooked certain sources of revenue for which we have published rates and from which we expect revenues.

I'm going to ask Mr. Sienkiewicz if he won't attempt to reconcile, if you will, some of the differences, all of them, hopefully, that exist between information we have published and the so-called Lazar report.

Mr. Weaver. Excuse me. It's that you have other revenues, you say, coming in?

Mr. Johnson. We have several categories of sales from which we anticipate revenues and for which we have established rates that we do not believe Mr. Lazar recognized.

Mr. Weaver. I see. What are they, Mr. Johnson?

Mr. Johnson. Well, I'm going to ask Mr. Sienkiewicz.

Mr. Weaver. Sure.

Mr. Johnson. Because we knew that you would want to reconcile the differences between numbers, and so we'll attempt to do that as clearly as we can right now.

Mr. Sienkiewicz. Mr. Chairman, for fiscal year 1984, which I think you earlier indicated you would like to cite on, there are revenues from the sale of surplus firm and new resources of $150 million which were not included in Mr. Lazar's analysis. There are sales from firm capacity of some $75 million which were not included in the analysis. Wheeling revenues of $86 million were also not included in that analysis. And there was another category of some $20 million. I believe that adds up to around $312 million of revenues which we have identified, revenue-producing categories which were not included in his analysis.

In addition to that, those are not the major revenue-producing categories for us. The major categories are sales under the priority firm rate schedule, under the industrial firm rate schedule, and under nonfirm.

And we examined each of these. And I think we find with respect to the priority firm rate not a great deal of difference in terms of the expectation either of sales or revenues that come out of our final 1983 rate filing.

There are differences in the industrial firm area, however. In fact, if our analysis is correct, Mr. Lazar's anticipated industrial sales exceed our expectation. He has some 24,000 gigawatt hours. We have 23,000 gigawatt hours. But, apparently, at least staff informs me, that the way in which he has applied the industrial firm rate is not appropriate, and therefore he has mis-estimated, we believe, the revenue expectation.

With respect to nonfirm sales, his expectation for sales is less than ours. We're not sure why. We think, in part, we inferred from his analysis an Intertie capacity of some 3,600 megawatts rather than the 4,500 megawatts that we're anticipating. And we think that, coupled with a misapplication of the nonfirm rates, probably led to an error in estimate.

We still believe that the rates which have been filed will, in fact, in fiscal year 1984, given the conditions that we have projected, produce $2.7 billion.

Mr. **Weaver**. My counsel tells me that Lazar's figures are your figures. He's just multiplied them together. So the discrepancy is difficult to come by.

Someone suggested that you have a broken model, the supply pricing model. I mean, do you have any idea?

Mr. **Sienkiewicz**. Yes, sir, there is a supply pricing model which has been used in connection with rate case for trying to determine what the out-year estimates for retail rates would be in the region, as well as future expectations about wholesale increases. That model needs additional work. I don't think it's appropriate to characterize it——

Mr. **Weaver**. It hasn't done the job up to now; is that it?

Mr. **Sienkiewicz**. Well, it is doing a job. It certainly needs more attention and further attention to the expectations about what will happen with the rates in July 1985. There are a lot of assumptions that have to be put into that model that, for study purposes, can be only that. There are a number of significant and controversial issues that derive from the rate directives in terms of our ratemaking for 1985 which a modeler can do nothing more than make assumptions about.

We take those results as only that, study results. They are not indicators of necessarily what the agency expects to occur as a result of the new rates which will go into effect in 1985.

Mr. **Weaver**. Thank you. Mr. Johnson, we will now switch to the rate structures themselves.

Mr. **Johnson**. Congressman?

Mr. **Weaver**. Yes, sir.

Mr. **Johnson**. Mr. Chairman, could I interrupt you just for a moment? We certainly would be willing, together with Mr. Lazar and Mr. Meek, if they would wish to go over this analysis that has been prepared by Mr. Lazar. We think at this time it's incomplete. It may have misleading information and it would be inappropriate to draw any conclusions from it now.

But we would be more than willing to sit down, as we have on previous occasions, and work out those differences, because we want the best information upon which to rely in making decisions, the same as you.

Mr. **Weaver**. Let's see. The Regional Act requires that the loads of the priority firm class be served first with Federal Base System resources. You have no discretion in making Federal Base System resources available to the priority firm class if their loads exceed the total amount of Federal Base System resources.

Is that correct?

Mr. **Johnson**. That's correct.

Mr. **Weaver**. And the Federal Base System is defined in the Regional Act, of course. Aren't the Federal Base System resources defined in Bonneville's power sales contracts with its preference customers? That's yes, right?

Mr. **Johnson**. They're defined in the Regional Power Act, yes.

Mr. **Weaver**. Do you believe that you have discretion to manipulate the Federal hydro resources so as to nominally reduce the amount of Federal Base System resources and thereby force the priority firm class to pay for more of the higher cost resources, such as Exchange resources? That's my question.

Mr. **Sienkiewicz**. If I may, Mr. Chairman, the issue of determining the size of the hydrosystem was one of significance and controversy in this particular rate case, because, in fact, we planned that system over a 4-year critical period, but for purposes of ratemaking are focusing on a subportion of that period. There are different ways in which one could reasonably construe the contribution of the Federal hydrosystem to resources for rate purposes.

There's a good deal of discussion about it, and I think, for purposes of this rate case, we have done what we call "uniforming" the hydrosystem over the full rate period. And that is the conclusion that we included in the final rates.

Mr. **Weaver**. Would you explain the rate that you're going to impose whereby, as I understand it, the utility provides you with their estimate of use. Let's say that's 100 megawatts. And if they use less, they use 90 megawatts, you make them pay a penalty. That's right. If they use less, they still pay a certain amount for what they didn't use of their estimate. Let's say they estimated 100 and they used 90. Do you make them pay something for that 10 megawatts that they didn't use?

If they used more, 110 megawatts, you'd make them pay a very sharply higher price for the 10 megawatts.

Would you explain that?

Mr. **Sienkiewicz**. Yes, sir. We do have a different approach to the planning that must go on with those utilities in the region that have their own generating resources. And essentially, what we agree to do is to meet their loads over and above the capability of their own resources.

Now what has occurred is that the circumstance in which we are planning to meet, in your example, the difference between the 100, which is their load, and the 90, which is our resource, we are planning to meet that 10 on a firm basis. And then a circumstance may come along in which it may be economic for that utility either to use its own nonfirm—not its firm power, but to use its own nonfirm—or, in fact, purchase power from someone else, because it happens to be in that condition cheaper.

We think that our obligation is to meet their load, both capacity and energy, and in the event that they don't take what we, in fact, have provided for them, there is an energy billing determinant, which has changed this year, which would increase the cost over and above the actual energy they take.

Mr. **Weaver**. Well, it would strike me that, if you didn't have enough electricity to go around, that rate might make some sense. But when you're dealing with a surplus and you're spilling water at times, that that rate has other objectives.

And it would strike me that one of the objectives of that rate would be to decrease the incentive of the utility to conserve, to develop its own power, or whatever, would it not?

Mr. **Sienkiewicz**. Well, we think we have a planning obligation to meet the net loads of those utilities, and in so doing, we incur costs. We think it's appropriate that the utilities, in fact, pay a fair share of those costs and that, in fact, the burden, that circumstances will subsequently change and they have other economic opportunity, should not fall to those utilities who do not have similar opportunities, who are not providing generation for themselves.

Mr. **Weaver.** Well, that may all be well and good, but what's the effect going to be? One, it's going to cause the generating utility to dump more nonfirm on the market, driving the price down, itself. It's a nice design, it strikes me, to get Bonneville a little more money, but its effect on the region is to seriously weaken some of these other utilities and also to take away incentive to conserve.

Mr. **Sienkiewicz.** I would suggest that the amount of nonfirm is going to be the same in either event. It's just a question of who has it on their system.

Mr. **Weaver.** Well, I understand that. Everything washes, doesn't it? So you've transferred something from yourselves to the local utility.

Mr. **Sienkiewicz.** We think we've transferred an appropriate sharing of the cost of our system.

Mr. **Weaver.** Well, I'm going to reserve judgment on that. I have not thought that out yet.

Mr. **Johnson.** Congressman, I would encourage you to look into that in more detail. It was a difficult decision to make. But I would believe that its result will be to encourage better utility planning decisions because of, I think, appropriate application of risk that arises to the whole region.

Mr. **Weaver.** Well, how far ahead do they have to give you those estimates that you rely on or that you mark this price on?

Mr. **Sienkiewicz.** I'm sorry, sir. I didn't hear that.

Mr. **Weaver.** How far ahead? They say they're going to use 100 megawatts and then they use 90. And then you give them your penalty on the 10 megawatts.

How much time ahead do they tell you, or when and where is the 100 megawatt rate set?

Mr. **Sienkiewicz.** They will indicate in advance of each operating year the amount of power.

Mr. **Weaver.** It's a year.

Mr. **Sienkiewicz.** On an annual basis, they tell us the amount that they expect to, in fact, take from us.

Mr. **Weaver.** In response to one of the committee member's questions, Mr. Johnson, I believe he asked if there was any more hydro. You said, roughly, no, none that could be competitive with nuclear, coal.

Isn't there considerable hydro available, hydroelectricity available, from British Columbia? I'm not talking about new developments; I'm talking about stuff they've got and are ready to sell.

As a matter of fact, isn't there 800 average megawatts of it and isn't that available for at least an estimated 10 years?

Mr. **Johnson.** It's my understanding that British Columbia Hydro, the utility in British Columbia, does have excess capacity, energy, at the present time. And I think that I've heard that figure, roughly 800 average megawatts, also.

But, Congressman, I did not say that there was not hydro within the region. There is hydro in the region. The very first acquisition made by the Administrator under the new Regional Power Act was a hydroresource in the city of Idaho Falls in Idaho. So we have already acquired a hydro resource, but they're much, much smaller in relationship to the earlier opportunities.

We'll continue to seek opportunities within the region to acquire cost effective hydro.

Mr. **Weaver**. But I'm talking about how much does British Columbia Hydro want for this electricity here? Oh, they haven't offered it. Oh, they haven't offered it.

If we had a massive conservation program in the Northwest, Mr. Johnson, and really much larger than you have conceived, a large conservation program going on which reduced the use of electricity by the people and businesses of the Northwest, would that result in lower revenues for the Bonneville Power Administration?

Mr. **Johnson**. It would depend on load growth. At the present time we are in surplus. So to offset further load, that might have an adverse impact on revenues. But anticipating load growth, certainly we would anticipate acquiring cost effective conservation, and I think that we would find that that would be a costeffective means by which the Administrator can meet his legal obligations.

Mr. **Weaver**. It would probably result in lower revenues for Bonneville, is that correct, if there were a large conservation program?

Mr. **Johnson**. If there were not load growth?

Mr. **Weaver**. Everything else being equal.

Mr. **Johnson**. That's correct. And you'd also have to factor in, if it exacerbated surplus, how wisely and effectively could we market that on a firm basis elsewhere. So all of those things, would have to be taken into account in answering your question definitively.

Mr. **Weaver**. I mean, given all your present, let's say all your present data, and you've have got to repay the Federal debt and do all these things, if this large conservation program is going on, you wouldn't get those revenues that you forecast right now, would you? People would use less electricity, right? And you wouldn't get your revenues.

Mr. **Johnson**. That's true, but, again, you would have to take into consideration, again, surpluses that might be greater because of that action and how effectively we could market that outside the region, which maybe wouldn't net any impact on the Agency's revenues.

Mr. **Weaver**. But you would use less electricity, and therefore the revenues you anticipate wouldn't be received.

The point I'm making is that some people think that Bonneville sees this and sees that it wouldn't be able to pay their debts and obligations and get the revenues it needs if there were a massive conservation program. So other people say, well, Bonneville is actively suppressing conservation in the Northwest, and one reason is because it would have revenue shortfalls with conservation programs to put through.

I just throw that out as a possibility.

I've asked you this question before. It's going to be my last question. Do you anticipate, after starting up WPPSS 2, keeping it running?

Mr. **Johnson**. Keeping it running?

Mr. **Weaver**. Yes.

Mr. **Johnson**. We are planning on that at this time. Based upon our analyses, that would be the wisest choice.

Mr. WEAVER. Now you paid Portland General Electric last year to shut down Trojan; right? You gave them extremely cheap electricity in order to shut down Trojan. Is that not correct?

Mr. JOHNSON. It's my understanding for a short period, the Trojan plant was closed down, I think arising out of circumstances particularly peculiar to that particular good water year, extraordinarily warm temperatures, and, as a consequence, the surplus and our ability to sell it outside the region.

Mr. WEAVER. Well, you have a surplus right now in the Bonneville region, do you not?

Mr. JOHNSON. Yes, we do.

Mr. WEAVER. Then why are you going to operate WPPSS 2?

Mr. JOHNSON. We believe that, and given all of our options, that that is the wisest choice because of our opportunity to sell both firm and nonfirm outside the region, what nonfirm there may be.

Mr. WEAVER. Right now, the tieline to California isn't full, but it could be made full by the existing hydro, could it not? Mr. Sienkiewicz?

Mr. SIENKIEWICZ. During this part of the year it could not, Mr. Chairman, because there is, under the workings of the coordination agreement in the region, we cannot construe ourselves in a circumstance in which we have nonfirm energy available for sale outside of the region. Therefore, we are not making such sales.

If, in fact, we were, and we were selling it at the 18.4 mills rate which will be in effect in early November, we can expect that the number of sales would increase significantly. The sales do, in fact, respond to the prices in the California region, and if more were made available at lower prices, we would expect the amount of sale to increase.

Mr. WEAVER. Well, now, my experience in business tells me that the more you have to sell of something, the lower the price you're going to get.

In other words, you have a glut of electricity now. If you bring WPPSS 2 on, you're going to have even more of a glut. The people in California are going to say, gosh, they've got all that electricity to sell. We'll hold off until they really hit a rockbottom price for us.

Doesn't that make sense, Mr. Sienkiewicz?

Mr. SIENKIEWICZ. Mr. Chairman, I think the analysis with respect to whether or not to keep WPPSS 2 running once, in fact, we've got it loaded and it's commercially operable is something that has to be taken into consideration at the time. There certainly is a circumstance, like the one that existed last year in which we purchased the rights to schedule Trojan, that could repeat itself.

On the other hand, I can also conceive of a circumstance in which, if we have a poor water year this year, the firm surplus contract which we expect to sign with the Western Area Power Administration within a month could not be honored in the months of March and April because we wouldn't have sufficient resource if WPPSS 2 were not available.

So there's a whole range of possible effects, and I think that our position is that, given where we are in terms of the completion of that project, it is prudent to continue on course and then to examine at the point what the incremental analysis would dictate we should do. Given the incremental variable costs of operating that plant and given the marketing condition of that day, do we make more revenue or not?

And the decision should be made under those conditions on the basis of that determination.

Mr. **Weaver**. So the decision to operate WPPSS 2 is not that you're going to, but, based on what you just said, if you have use for the electricity at a price that's worthwhile.

Mr. **Sienkiewicz**. That's correct, sir. But that determination would be made on an incremental basis, and it's difficult, at least for me at this point, to conceive of a circumstance in which we would not be able to cover the variable costs of that project.

Mr. **Weaver**. Well, thank you very much, all of you. I appreciate very much your patience in staying with us so long. We appreciate, Mr. Johnson, your coming back here and giving us this testimony.

We'll call Robert Greening and Ken Dyar to the stand, and Richard Bidwell, Bernard Palk, and Charles Imbrecht.

Mr. Greening, you're first on our list. Do you have a written prepared statement?

[Prepared statement of Robert Greening, with attachments, may be found in the appendix].

STATEMENT OF ROBERT GREENING, MANAGER, PUBLIC POWER COUNCIL

Mr. **Greening**. Mr. Chairman, I have already submitted a written statement for the record, as well as our answers to the questions posed by the committee.

I have a very short statement that I would like to give to the committee.

Mr. **Weaver**. Please do.

Mr. **Greening**. First, I would like to correct a couple of things that are in the written statement. I think the public generating utilities were understandably a little upset when the impression might have been left by the fourth paragraph on page 2 that they are the only ones suing Bonneville over the rates.

Quite to the contrary, everybody is suing Bonneville over the rates. [Laughter.]

And I didn't mean to leave the impression that they should be singled out.

The second correction is in my answer to question 5. I don't want to leave the impression with the chairman that we believe that the WPPSS costs are the only reasons for the Bonneville rate increases. In fact, as Mr. Ailshie pointed out earlier, the cost of the residential exchange is only $90 million less than the WPPSS increases.

Mr. **Weaver**. No, no, wait a minute.

Mr. **Greening**. I wondered when I was going to get your attention.

Mr. **Weaver**. You got my attention. [Laughter.]

The one thing that I do not allow my staff to do is ever use statistics to lie. And if they do, on my behalf, in my interest, I say let those statistics stand for scrutiny.

Mr. **Greening**. Good. Let's do that.

Mr. WEAVER. So let's talk about the Residential Exchange for what it really is.

Mr. GREENING. What is it?

Mr. WEAVER. The net, the actual net.

Mr. GREENING. The net Residential Exchange we calculate on this basis. The investor-owned utilities sell to Bonneville. It is a Bonneville cost, approximately $1.1 billion in power.

Now you're right. It's a bookkeeping transaction. But they buy back from Bonneville——

Mr. WEAVER. That's right.

Mr. GREENING [continuing]. About half that amount, about $500 or $600 million.

So the net cost of the Exchange is the difference between the amount that they sell and the amount that they buy back, which is about, it's in excess of $500 million.

Mr. WEAVER. My subcommittee counsel, Mr. Meek, sitting next to me, has in his report to me shown that the net Residential Exchange in fiscal year 1983 is $106 million, in 1984 is $236 million, and in 1985 is $327 million.

Mr. GREENING. Perhaps your counsel, Mr. Meek, could explain how he derived those figures, because I believe them to be incorrect.

Mr. WEAVER. These are Bonneville's figures submitted to the subcommittee this week.

Mr. GREENING. Bonneville said earlier, and we concur with their figure, that the net cost of the exchange is over $500 million. We know that very well, Mr. Weaver, because we participated in the rate hearings for 7 months and we, the priority firm customers, are paying 40 percent of it. We know what it is.

Mr. WEAVER. Well, you're going to embarrass my subcommittee counsel a great deal. [Laughter.]

Mr. GREENING. Well, I don't mean to embarrass anyone.

Mr. WEAVER. No, no, no, no.

Mr. GREENING. I think Mr. Meek has done——

Mr. WEAVER. I want the correct facts and I'm going to get them, I can assure you.

Mr. GREENING. I want to say to Mr. Meek, in the amount of time that he has to prepare for this hearing, has done an admirable job of collecting a lot of facts to focus on the important points.

But I do want to clear up that the WPPSS cost increases, as great as they are, are not the only reason for our rates going up. The Regional Act, which you, Mr. Chairman, opposed, in retrospect quite rightly, is also responsible for a substantial number of the cost increases, the Residential Exchange being the No. 1 cost increase.

Now that the record is corrected, would you like me to go on with my statement?

Mr. WEAVER. No; this is extremely important on the Residential Exchange. My subcommittee counsel has showed me a figure and it says—would you please explain it? I'll have the subcommittee counsel explain it.

Mr. MEEK. By net Residential Exchange, I'm taking the cost of the Exchange to Bonneville of purchasing the power from the exchanging utilities.

Mr. **Greening**. What's that figure?

Mr. **Meek**. For which year?

Mr. **Greening**. Fiscal year 1984. Or take any year that you want to take. My understanding is that it's over $1 billion.

Mr. **Meek**. OK. For the Residential Exchange, if we take fiscal year 1983, for example, the cost of the Residential Exchange is $543.6 million. That's what Bonneville pays to the exchanging utilities for the power. At the same time, Bonneville is collecting from those exchanging utilities, under the priority firm rate, $437.3 million. The net cost of the exchange for fiscal year 1983 was thus $106.3 million. In Bonneville's testimony, net Residential Exchange expenses for fiscal year 1982 was $211.8 million. For fiscal year 1983, they were $106.3 million. For fiscal year 1984, they are projecting $235.8 million.

So the net cost of the exchange is actually——

Mr. **Greening**. What is the figure; I'm thinking in terms of the figures generated in the 1984 rate case. And since I didn't realize that we were going to have this, I don't have them with me. But what is the net amount—what is the amount that Bonneville is paying the private utilities in—let's take an example—operating year 1985.

Mr. **Meek**. OK. If you can give me a minute, I can find that. And in the meantime, I think the chairman can proceed with his questions.

Mr. **Weaver**. Right.

Mr. Greening, you were saying when I interrupted you——

Mr. **Greening**. I think, Mr. Weaver, I might also be wrong. I think our problem is the same problem that you may have had with Mr. Johnson, and that is not speaking with the same set of figures and the same years because, as you pointed out, there's operating years, fiscal years, calendar years, and then the 20-month rate period.

Carol Opatrny, who is an economist with Seattle City Light, has just done a back-of-the-envelope calculation that would show in fiscal year 1985 the cost of the Exchange will have to be at least $330 million, which is a significant amount of money. And I certainly don't want to argue over the figures, Mr. Weaver.

Mr. **Weaver**. Yes; that's the figure we have.

Mr. **Greening**. OK.

Mr. **Weaver**. This is a hearing before a congressional committee, and I insist on having accurate figures.

Mr. **Greening**. Good. My point is not the exact amount of the figure, but that the Regional Power Act has imposed substantial costs on the system which we have to absorb and which are causing, in addition to the WPPSS cost increases, part of the problem.

Mr. **Weaver**. No question.

Mr. **Greening**. OK. That's my only point. And the two things that I want to say in my oral presentation are simply that, as Bonneville's preference customers, we believe that Bonneville is on, based on its 1983 rate proceeding and its proposed 20-month rates, on the right financial course. And it does stand a good chance of making the Federal repayments.

The second point is that we are very concerned that Bonneville and Congress honor the commitment that you made as Congress and that Bonneville made in the Regional Power Act to protect our rates to the rate ceiling.

On the first point, in the 1983 rate proceeding, we have worked closely with Bonneville in improving their load forecast which will improve their revenue forecast. You're absolutely correct and the GAO is correct that they have not done a good job in the past. We believe that they are well on their way to doing good load forecasts now.

Mr. **Weaver**. Why?

Mr. **Greening**. Because, in the past——

Mr. **Weaver**. What have they changed?

Mr. **Greening**. They have changed the method by which they were modeling their forecasts and the method by which they were aggregating the smaller utility forecasts.

In past years, and even in the present, many of the smaller utilities don't do any of their own forecasting. Bonneville did much of it for them. Many of these forecasts were quite optimistic. Let me give you an example.

A small utility, several small utilities in one area might be candidates for a new potato processing plant. Each one of those utilities may have put the potato processing plant in their forecasts, which inflated the load forecast. And Bonneville local area economists worked on those load forecasts, and it was not done in an extremely sophisticated manner.

Now, both the DSI load forecasting model and the econometric forecasts they're using for the nongenerating utilities are much more sophisticated and, therefore, we think, much more accurate.

Over the 20-month rate period, which is the most important thing, Mr. Chairman, there is very little load growth at all except on the DSIs, and that is based on improved economic conditions.

Mr. **Weaver**. The 10-percent projected load growth on the public utilities, Mr. Greening, that's rather sizable.

Mr. **Greening**. What public utilities?

Mr. **Weaver**. The aggregate.

Mr. **Greening**. Well, if I may refer to the question which the committee asked, the first question is why the forecast for the publicly owned utilities showed a substantial increase in the generating utilities' loads over the—well, you were comparing fiscal year 1985, operating year 1985, and fiscal year 1983. We have demonstrated in our answer to that question that nearly all of that increase is due to two things. One is that three PUDs—Clark, Cowlitz & Douglas—were not included in the fiscal year 1983 figure, whereas they were included in the fiscal year 1985 figure. Therefore, that is 75 percent of that increase. And the remaining increase is due to the ratchet, which you have already discussed with Mr. Siekiewicz.

Mr. **Weaver**. We did aggregate all the publics, Mr. Greening, including those, when we came up with our figures.

We will go on to Mr. Dyar now, unless——

Mr. **Greening**. Well, I would like to make my final point, Mr. Weaver.

Mr. **Weaver**. Sure.

Mr. **Greening**. Which is probably the most important. I was quite astounded and disturbed to read question No. 3 in your questions submitted to us, because your constituents in the Eugene

Water & Electric Board, the Springfield Utility Board, Lane Electric Coop, are depending upon the rate ceiling, the rate test, as a protection against your rates. And yet, you suggest in your question that Bonneville might have some discretion in dealing with the rate limit.

We are emphatically determined that Bonneville and Congress must honor its commitment on the rate ceiling.

You know that we were reluctant participants in this process. You were opposed to this process, Mr. Weaver. The carrot that was held out was the rate ceiling. The investor-owned utilities acknowledged and accepted the risk that things might not turn out as good as Bonneville had predicted and others had predicted.

The fact is, this rate ceiling is designed to protect against the exact type of circumstances change that we have right now.

And so we hope that you intend to honor your commitment as a Member of Congress, and we certainly urge Bonneville to do the same.

Mr. **Weaver**. You're getting mad at the questioner, huh? [Laughter.]

Well, look, in my estimation, Bonneville has constantly gone its own way, time and time again. And if you haven't noted that, then perhaps you don't interpret the laws as I do.

And all we're asking is whether Bonneville should do this.

Mr. **Greening**. Well, the question suggests that Bonneville has the authority or the discretion to do it, and it's certainly not within their authority or discretion.

Mr. **Weaver**. I'll repeat myself. Bonneville, in my estimation, has violated the law again, again, again, and again, various laws. It violated the Northwest Power Act again, and again, and again. I don't think they're even close to coming up to the law in terms of the conservation programs and the renewable resource programs that are required, and in many other areas as well.

And so, when we have Bonneville, as the Federal Energy Regulatory Commission said, a renegade outfit, we've got to ask these questions, don't we?

Mr. **Greening**. Well, Mr. Weaver——

Mr. **Weaver**. May I say whether the law says one thing or another, they could do this.

Mr. **Greening**. I'm glad that you have cleared up that misunderstanding. And I know that you, not only as a Congressman representing a district with lots of public utilities, but also as Chairman of this subcommittee, will make sure that Bonneville does not interpret the Regional Act as this question suggests, but that Bonneville honors its commitment.

So we thank you.

Mr. **Weaver**. It will be the first time, Mr. Greening, that Bonneville ever did something at my insistence. [Laughter.]

Mr. **Greening**. But you'll be watching closely, I'm sure.

Mr. **Weaver**. I can assure you I will. But, nevertheless, it does look as though, does it not, that when those 1985 rate test clauses are triggered, that there will be no Residential Exchange, does it not?

Mr. **Greening**. I'll get my handkerchief to weep. No; I don't really have a tremendous amount of sympathy for the investor-owned utilities on this matter, because they acknowledged and accepted the risk. And, quite frankly, Mr. Craig, I think, is misinterpreting the Power Act also, because the direct service industries acknowledged and accepted the risk that they would have to underwrite the Residential Exchange and that Exchange would be very costly for them.

Mr. **Weaver**. Well, I understand that. Mr. Charles Imbrecht, chairman of the California Energy Commission.

Do you have a statement, please?

STATEMENT OF CHARLES IMBRECHT, CHAIRMAN, CALIFORNIA ENERGY COMMISSION

Mr. **Imbrecht**. Yes, thank you very much, Mr. Chairman. I appreciate you taking me a little ahead of schedule. I do have another time conflict.

If I could just indicate as well that I would appreciate my remarks I'm about to offer being used as the official record representing my views. As I reviewed the document that had been prepared, I found a few rhetorical flourishes that had been added by my staff which I was not comfortable with. So I have made some amendments in the course of these remarks.

I want to thank you for your invitation to appear here today to discuss our views on BPA rate issues. When Governor Deukmejian appointed me as chairman of the Energy Commission and also to serve as his principal energy advisor, he also charged me with the task of finding ways to reduce the cost of power in our State, particularly as it relates to economic development.

Recent surveys of factors affecting the business climate in California indicate that electricity prices are one of, if not the single, principal influence on business location decisions. After a view of a variety of strategies, we have concluded that the potential for cooperation with the Northwest, and we hope a new era of cooperation, is very great. And that is another reason why I have made an effort personally to participate in each of the public forums that have been held in the course of this year to try to demonstrate that, indeed, California is trying to approach this issue from a different perspective than in the past.

The California Energy Commission has also been a very active participant in BPA rate cases for the last 6 years. And it is from this degree of involvement that I would like to respond to the questions you raised.

My first concern is that, while I believe ratepayers, both in the Northwest and in California, stand to benefit by hundreds of millions of dollars per year from continued and increased power transactions, recent actions taken by BPA have produced a chilling effect on the discussions to expand those transactions.

Quite obviously, if BPA and other utilities in the Northwest can sell more power to California, especially power with a greater certainty of delivery that commands, therefore, a higher price, revenues will be increased. Increased revenues will obviously go directly to BPA's ability to make repayments to the Federal Treasury.

I believe that there could be substantial interest among California utilities in buying more power and in buying the higher valued firm surplus that appears to be available, depending on the price, terms and length of sale. The main physical obstacle, as you are well aware, is the construction of additional transmission capacity in our state to provide a route for the added flow of power from the Northwest. A new transmission capacity, we estimate, will cost in the neighborhood of one-half billion dollars.

Clearly, then, in order for our utilities to justify the construction of that transmission capacity, the benefits have to be justifiable to our own ratepayers.

In theory, the benefits of new transmission and expanded transactions are large enough to allow a compromise to be worked out. The Northwest has a temporary firm surplus which California could use to meet its peak demand and can exchange generation in the winter and summer months. And we have made very clear in the course of the discussions that we are prepared to use our own additional generating capacity as a backup to dry years or other exigencies that might develop in terms of Northwest supply.

Over the long term, a new line will allow California to buy more of the nonfirm energy which is now spilled in wet years. We think that there can be a new era of cooperation. And we will bend over backwards, and I have the personal instruction of the Governor to make sure that we do that and try to resolve some of the historical problems that have existed in the past. But it's going to require cooperation from both sides. We are particularly concerned about some of the obstacles that Bonneville has recently erected.

I'd like to explain my perspective on those obstacles. The first is BPA's attempt at regional price discrimination. Under the new rates, BPA can charge California 18½ mills per kilowatthour for nonfirm energy, while it sells the same power to the Northwest to displace nuclear or coal for only 3 to 7 mills per kilowatthour.

Since 1979, BPA has been trying to find a way to charge higher prices to California and lower prices to Northwest, but without success. The 1983 rates are just the most recent attempt in that endeavor. We find these effort misdirected and grossly unfair.

BPA justifies its attempts on the basis that the power is of higher value to California because of our higher generation cost. That is a little bit like charging less developed countries a higher price for surplus grain than is charged domestically on the grounds that people in those less developed countries are closer to starvation and should value the food more.

And I might mention as well that our taxpayers have obviously contributed, as the Nation as a whole has, to the entire development of Federal power projects.

Mr. **Weaver**. In light of what you just said, Mr. Imbrecht, do you think that Bonneville's projected revenue increases of 67 percent from California for fiscal year 1984 will be met?

Mr. **Imbrecht**. No, I do not. In fact, that's one of the principal concerns that I wanted to express to you. We think that those estimates are very high, and I think it's important to recognize that California has a variety of other markets to turn to for competitive power purchases.

Mr. **Weaver**. What are they?

Mr. **Imbrecht**. The Southwest and, of course——

Mr. **Weaver**. Arizona?

Mr. IMBRECHT. That's correct.

Mr. WEAVER. Utah?

Mr. IMBRECHT. And New Mexico, as well.

Mr. WEAVER. New Mexico? All have surpluses, don't they?

Mr. IMBRECHT. That is correct. And we are also, I might say, engaged in discussions with the Southwestern States in terms of increasing transmission capacity.

Mr. WEAVER. So you are in the enviable position of having a whole bunch of eager sellers, and you're bargaining with them; right?

Mr. IMBRECHT. Pardon me?

Mr. WEAVER. I say you are in a position of having a whole bunch of eager sellers trying to sell to you, and you're bargaining with them; is that correct?

Mr. IMBRECHT. Well, to some extent. But I think it's also—I want to make it very clear that we are fully prepared to pay higher prices than we have in the past and to try to rectify the perception that I believe exists in some quarters in the Northwest as to methods that California in the past has used to deal in these matters.

Mr. WEAVER. Well, I mean, are you doing this out of the goodness of your heart?

Mr. IMBRECHT. Obviously, we believe it's in the self-interest of our ratepayers. But we also believe that it's in the self-interest of the Northwest ratepayers and of the Federal taxpayer as well. Obviously, in order for the Northwest to enjoy additional capital from California, there has to be a rate structure and package that fairly reflects the interests of both regions.

We don't believe that the most recent price differential formulas that have been enunciated by BPA reflect that principle.

Would you like me to continue or do you prefer to go to——

Mr. WEAVER. No; if you need to leave, please continue, because I'm going to have to go vote in a few minutes. I was hoping that we could finish your testimony.

Mr. IMBRECHT. If I can just try to summarize briefly, we are particularly concerned about the price levels that BPA has attached to both firm and nonfirm. We think that they are both too high in light of market conditions. We think that the erratic nature of BPA rate policies over the last several years has made it very difficult for California utilities to make the kind of projections necessary and have the confidence that there will be stability in those projections in order to justify the investment in the transmission capacity.

I might say as well that we are concerned about BPA's efforts and those of others in the Northwest to develop economically marginal uses for nonfirm energy in the Northwest. We think this policy reduces the benefits for expanded transmission.

We also believe, obviously, the Northwest has every right to promote its own regional economic growth. However, where the BPA rates result in selling power to industry at promotional rates below what California utilities would pay, either other Northwest ratepayers will be subsidizing those industrial sales or BPA will be deferring even further its repayments to the Federal Treasury. And I think you brought those points out quite succinctly in your questioning earlier in today's testimony.

Mr. **Weaver**. Would you repeat that, please?

Mr. **Imbrecht**. I said that I think you brought those points——

Mr. **Weaver**. No; the part about the industrial subsidies.

Mr. **Imbrecht**. I said we have concern that BPA is selling or is suggesting the sale of power to industry in the Northwest at promotional rates below what California utilities would pay. That either means that other Northwest ratepayers will be subsidizing those industrial sales or BPA will be deferring even further its repayments to the Federal Treasury.

Mr. **Weaver**. Thank you.

Mr. **Imbrecht**. Both of those conclusions, in our view, would be an unfortunate result from such a policy. And I think you understand that by virtue of your earlier questioning today.

Many utilities in California feel that by threatening to dump surplus power, the Northwest is trying to force them into overpriced contracts. We think that we should be given an opportunity to bid for excess, nonfirm energy in a free and open market.

The result of these five obstacles is that BPA will collect less revenue from California utilities than it projects, as I mentioned a moment ago. In the short run, the pricing of nonfirm in the new rates will probably mean that California will buy power from the Southwest and reject purchases from BPA more frequently. I think you see some indication of that already occurring in the sense that the Intertie is not full.

If BPA successfully blocks more attractively priced sales by other utilities in the Northwest, the whole region might lose revenue. I can't estimate the size of that loss, simply because the rates from BPA involve so much discretion in how they are applied that it's very difficult for anyone to predict exactly what will happen.

More importantly, because of doubts created by BPA's actions, the interests of most California utilities in entering into a long-term sale of sufficient magnitude to justify new transmission has significantly waned. BPA's estimates of firm sales of about 700 average megawatts is now likely to be too high.

Discussions are still under way, and I want to make it clear that I have been attempting, personally, to insure that we continue to talk, because we do not want to see unfortunate atmospheric conditions interfere with what we continue to believe is in the best interests of both regions.

However, it now appears that an inexpensive upgrade of transmission capacity will be technically limited, if it's feasible at all. And therefore, substantial investment in new transmission is going to be required.

Realistically, we think the Northwest has got to take this capital investment cost into account when it sets its price and other terms for long-term firm power offers.

If BPA continues in the current direction, it runs a significant risk of collecting revenues substantially below its estimates and below its needs. Those undercollections will only add to the revenue difficulties in future periods. The strategy, therefore, will tend to heighten confrontation rather than contributing to the accommodation which I do believe, as I mentioned earlier, would benefit both regions.

Let me just briefly hit for you several essential reforms in the BPA rate procedure to stabilize revenues and reduce the tensions between the regions which we think would be important.

First, it's important to end regional pricing discrimination. Instead of fighting this simple economic fact, BPA should rely less on revenue from uncertain nonfirm sales and concentrate on recovering from its firm customers the full cost of providing its firm service.

Second, we think that there should be an adoption of a long-term rate formula using more predictable components in order to allow our utilities to count on the benefits of expanded transmission and to justify the capital investment required, therefore.

Third, we believe that there should be an elimination of anticompetitive surcharges and access limitations. If BPA finds that it cannot sell all its surplus at the rates that it established, that should be a clear signal that the price is simply too high. The response should be what any businessman would do—to lower prices, not to put shackles on competition.

In addition to these substantive reforms, procedural reforms would also be useful. One of the most grievous features of the current ratemaking process is that the Bonneville Power Administration acts as prosecutor, judge, jury and executioner. There is little opportunity for impartial review.

While the law requires FERC approval of BPA rates, as a practical matter, FERC review has been too limited and too late, with the possible exception of the decision yesterday.

In concept, the two suggestions of reforms in the committee's invitation are good ideas, H.R. 3177 and the 6-month FERC review and confirmation required before new rates become effective.

I'd like to add a couple of modifications and improvements.

Mr. WEAVER. Mr. Imbrecht, I'm going to have to go vote.

Mr. IMBRECHT. OK.

Mr. WEAVER. If you do wish to depart and have to depart, you may. But I'll be back in 5 to 7 minutes.

Mr. IMBRECHT. Fine. Thank you, Mr. Chairman.

AFTER RECESS

Mr. WEAVER. The subcommittee will be in session.

Mr. Imbrecht, please continue.

Mr. IMBRECHT. Yes; thank you, Mr. Chairman. You were very rapid in returning.

I neglected to mention one point, and that is that by virtue of pricing the surplus at unrealistic levels, BPA, to some extent, has antagonized some of our utilities by trying to cut off competition from utilities with cheaper power to sell.

In the 1983 rate case, BPA proposed, but did not ultimately adopt, an opportunity cost transmission surcharge on power that would compete with BPA's sales. Even worse, it did adopt what California utilities are politely referring to as the disappearing spill rate. BPA originally proposed eliminating the spill rate, previously 9 mills, now it's 11 mills per kilowatthour, in order to charge the higher 18½ mills standard rate.

The California Energy Commission and our utilities pointed out that the proposal is unrealistic, since thermal plants in the Northwest could undercut BPA's 18½ mills price. BPA's response was to make the spill rate optional. The message to the other Northwest utilities is clear and disturbing to us. If they refrain from competition with BPA standard rate sales, they will be able to make some sales under BPA's 18½ mills price umbrella and receive 3 or 7 mill power as well. If they dare to compete, however, BPA will drop its price to 11 mills, depressing the price received by all utilities in the Northwest.

This disappearing spill rate, like the transmission surcharge, looks to us like an attempt to exert the power of market dominance by BPA to squeeze out competition to charge excessive prices. In the private sector, this policy would certainly raise antitrust implications.

Last, I just want to mention the three procedural additions that we would suggest for your consideration in H.R. 3177. That would be to authorize FERC, rather than BPA, to appoint the hearing officer in the rate cases. We think that that provides some measure of added independence in the decision process.

Second, we would like to suggest that requiring the BPA to submit rate proposals for hearing 12 months before they are due to become effective to insure adequate time for review. I think one of our utilities, in other testimony today, has characterized those changing numbers as kind of a moving target. That has been a major problem for us.

And last, to require a renoticing of any changes in the BPA Administrator's rate proposal to be sure that all affected parties are aware of contemplated changes and have an adequate opportunity to respond.

Let me just conclude by saying that we very much want to work with the Bonneville Power Administration and with all of the interests and entities in the Northwest. We do believe that, ultimately, we can find a solution that will mean an infusion in the neighborhood of a quarter of a billion dollars annually to the Northwest and a like savings to our ratepayers as well.

We do not come to the Northwest with a robber-baron perspective. We come hat-in-hand in a sincere effort to try to work cooperatively with our neighbors in the Pacific region.

Thank you very much.

Mr. WEAVER. Well, Mr. Imbrecht, thank you very much for some excellent testimony. But, you know, why should we sell, why should the Northwest sell electricity to California cheaper than our own utilities buy it from Bonneville? I appreciate very much your offer of cooperation. That's very good, and I hope we get it from both sides. That would be excellent.

But I'm told by our utilities that they want some of that cheap power. And I'm also told by industrial users that they would like some of that cheap power as well.

Mr. IMBRECHT. What we're suggesting is that we be allowed to compete in a free and open market. We're not suggesting that there be a price differential in our favor. We are suggesting as well that a price differential in favor of Northwestern interests is equally unfair and has very substantial implications in terms of whether or not the Northwest will ultimately be able to enjoy that infusion of dollars from California.

Mr. WEAVER. Sure. But our utilities and industrial users would like that free market, but they don't get it. Bonneville sets their rates. Why shouldn't Bonneville set the rates for California?

Mr. IMBRECHT. What we're suggesting is that Bonneville set rates to California, as well as to the entities in the Northwest, that are based upon the same pricing structure. Regional discrimination of prices only has the impact of reducing the potential market of Northwest surplus in our State and forcing us to examine other alternatives.

Mr. WEAVER. You think that Bonneville is asking some of the Northwest utilities, generating utilities, not to sell to California, so that you will have to buy their higher priced electricity?

Mr. IMBRECHT. We think that that is the implication of their policies, as I enunciated a few moments ago, yes.

Mr. WEAVER. Well, what's wrong with that?

Mr. IMBRECHT. Well, as I indicated, in the private sector, that type of activity would raise substantial antitrust implications. I might say as well that having a dominant force in the market place, in my view, does not offer justification for exercise of that power. That's why the Congress passed things like the Sherman Antitrust Act and other provisions years ago to deal with private sector abuses of that nature.

Ultimately, when you examine some of the suggestions about price for firm surplus from the Northwest, we have tried to make it as patently clear as possible that we fully expect to pay substantially higher prices than have been paid in the past for nonfirm sales.

But, at the same time, the price has to be realistic in the context of——

Mr. WEAVER. 18½ mills is not realistic?

Mr. IMBRECHT. No; not for nonfirm because it will not justify the transmission—that does not provide any certainty of supply for a long enough period.

Mr. WEAVER. Has Bonneville offered you long-term power?

Mr. IMBRECHT. We have had a number of discussions with a collective entity of Northwest interests. And there have been some discussions. We, frankly, at the most recent meeting found the price offer for long-term firm to be substantially greater than could possibly be justified to add the transmission capacity.

In fact, the terms that were discussed were in the neighborhood of what we can today build and put on line in our own State, geothermal resources. And we think it's highly unrealistic to suggest prices in that range, on top of which must be added the capital costs associated with the transmission line.

Mr. WEAVER. Can you buy B.C. Hydropower?

Mr. IMBRECHT. Well, the difficulty obviously is that that has to come down through the Northwest regional network.

Mr. WEAVER. So Bonneville could stop you from buying it; is that right?

Mr. IMBRECHT. I don't really know whether they could stop us. That's not an issue that I can address to the degree of certainty that you probably would require.

I do know that there have been obstacles in the past associated with that, and we would, of course, be interested in pursuing additional surplus from them as well. But I also would like to make it clear that we believe that we can offer substantial backup guarantees for the Northwest in terms of making available and retaining the operating capacity of our fossil fuel thermal generation plants for dry-year safety margins, because, obviously, the power can flow either direction on those lines.

But until we add the third line and do whatever upgrades are technologically feasible to the existing lines, we're going to be in a situation where you have a bottleneck in delivery ability in terms of marketing and, in addition, you have other factors competing with our desire to buy power at a reasonable price.

Just to put it into some context, we have enunciated on a number of occasions that for a firm, long-term surplus sales agreement, we believe a fair price is in the neighborhood of 30 to 40 mills. That's obviously, I think, an indication of the fact that we are not talking about a rape kind of price of the Northwest in the neighborhood of 9 or 11 or even 18 mills.

Mr. WEAVER. Is there adequate tieline capacity from Arizona and New Mexico to get the electricity in for you to use?

Mr. IMBRECHT. Well, there is some transmission under construction right now, particularly at the San Diego Gas & Electric Co. I believe Southern California Edison Co. has a part of that as well.

This would require an additional transmission line to the Southwest as well.

We, frankly, would like to work out cooperative agreements with both regions. And I want to emphasize that we are not trying to leverage one region against the other. I have tried in all of my presentations to be as open and direct about these things as we possibly can, even to the point that, obviously, when I talk of those price ranges, that's not something that all of the entities in California are delighted to hear being said. But we have tried to be realistic in making those statements, to try to demonstrate to people in the Northwest that we're not trying to replay scenarios of the last 10 years about how California deals with the Northwest on these issues.

Mr. WEAVER. I understand that San Onofre 2 and 3 are now on line and producing electricity, or the last I heard SONGS 3 was close to that.

Mr. IMBRECHT. Close to it, yes.

Mr. WEAVER. So that takes away a little bit of your demand. How about Diablo Canyon? Is that ever going to come on line? If so——

Mr. IMBRECHT. We expect it will, yes.

Mr. WEAVER. Years from now?

Mr. IMBRECHT. No; my guess is sometime in 1984, perhaps relatively early. They have been given their license for low-power testing, and so as a consequence, the process is back in place.

Mr. WEAVER. So all you're doing now in buying this surplus power is shutting off your oil-fired generation; is that right?

Mr. IMBRECHT. But not tearing them down. And that's an important point that I think needs to be stressed. Of course, we have environmental considerations in California in terms of air quality that are important to us as well.

But we also are obviously concerned about the rates and the very high cost of energy that our citizens must deal with. That is a factor of major concern to us and we are looking for ways, obviously, to displace our dependence upon fossil fuels.

Because of that much greater percentage of dependence than other states, we continue, of course, to be concerned about price dislocations in the international oil market, particularly with the uncertainties of what may happen in the Middle East based upon recent events.

Mr. WEAVER. Sure. My colleague from Idaho has returned, and this is Mr. Imbrecht of the California Energy Commission, who has just testified that he doubts severely that Bonneville's projections of revenue from California will be met.

He says he can't imagine that they will. And he must leave, so if you have any questions of Mr. Imbrecht, please make them at this time.

Mr. CRAIG. Thank you, Mr. Chairman. I'm sorry that I did not get here for your testimony. I'll read it with great interest, because I think this committee's concern clearly rests in the area of BPA and those projections of revenue and those rate increases that are proposed. But I have no questions at this time. Thank you, Mr. Chairman.

Mr. WEAVER. Thank you very much. Thank you, Mr. Imbrecht. We appreciate your coming.

Mr. IMBRECHT. Thank you, Mr. Chairman, and members.

Mr. WEAVER. Mr. Dyar.

[Prepared statement of R. Ken Dyar may be found in the appendix.]

STATEMENT OF R. KEN DYAR, CENTRAL LINCOLN PEOPLES UTILITY DISTRICT, ACCOMPANIED BY KEN LARSEN, REPRESENTING THE PUBLIC GENERATING UTILITIES

Mr. DYAR. Thank you, Mr. Chairman. I'm Ken Dyar. The written testimony has been given to the clerk and I request that it be entered into the record.

Mr. WEAVER. All written testimony will be entered into the record, yes.

Mr. DYAR. Thank you, Mr. Chairman. I'd also like to introduce several people that are with me today. If we get into technical questions, they'll be assisting me in those answers.

They are Ms. Carol Opatrny. She's an engineer-economist for Seattle City Light. Mr. Walt Williams, counsel for Seattle City Light. And Mr. Al Larsen, attorney for Central Lincoln PUD.

Mr. WEAVER. Thank you.

Mr. DYAR. Mr. Chairman, we're not going to rehash the 1983 rate case before this subcommittee hearing, other than to say that we are deeply concerned about the philosophy and some of the policy decisions that have been made by the Administrator in the course of this 1983 case. One which we believe to be, first and foremost in our mind, and obviously the most damaging to the preference customers that I'm testifying for today—which include the cities of Seattle, Eugene, four very large generating public utilities in the State of Washington—Cowlitz, Chelan, Douglas, Grant PUDs—and, of course, Central Lincoln PUD—and that is what we believe to be a violation of preference and priority on the part of the Administrator in the pricing of the Federal Columbia River Power System. The second one is in the abuse of his discretion that's allowed under Public Law 96-501.

In the first instance, in the violation of preference and priority as to price, we believe that the Bonneville Project Act, Public Law 96-501 and the references in the legislative history, particularly Regional Act sections 5(a), 7(b), and 10(c), make it clear that the publicly-owned utilities and cooperatives have preference as to supply and as to price.

The Administrator and his staff in this rate case artificially reduced the size of the Federal Base System resources, as defined by the Act. And by artificially reducing the gross size of the resources, it moved the cost allocations of the investor-owned utility Exchange program over to be borne by the public agencies. And those costs represent about 4 mills per kilowatthour to the preference customers.

The actual size of the Federal Base System is more than enough to cover the loads of the public agencies being served. So, therefore, it's a paper transaction and a manipulation of the numbers.

On the question of abuse of discretion, Public Law 96-501 allows great discretion on the part of the Administrator to establish and set rates. For many years, the Administrator encouraged the utilities to create their own generation and use their generating resources to meet their loads. In this rate case, however, he has decided that, because of the surpluses that exist on the Northwest power system, he would institute what is a so-called "availability charge on the generating public utilities.

This availability charge will penalize those generating publics, thereby, in effect, shifting the surplus on to those utilities. While it is a small revenue producer potentially for Bonneville, we do believe, and submitted to the Administrator, there are various other ways for him to raise those funds.

The third portion of my prepared testimony gets into the question of the 1984-85 rate case and in the post 1984-85 rates for the aluminum companies.

We are very concerned about the direction of the philosophy and the policy decisions in future rate cases, particularly in the post 1984-85 period. The DSI rates are based upon a loose set of standards that is contained in section 7 of Public Law 96-501. It seems to us that, if the philosophy and the policy decisions continue in the direction that they have been going, that the aluminum companies will have a very artificial low floor for their power rates from Bonneville. Then Bonneville will argue with us about whatever this loose set of standards will mean in terms of the establishment of the DSI rate, because the statute provides that the rate to the DSIs will be no less than what it was established in 1984-85.

Of course, the other issue dealing with preference and priority is the question surrounding the methodology of the section 7(b)(2) program, which insures preference to price for the publicly-owned utilities.

The section 7(b)(2) rate test, as it's called, the methodology was supposed to be completed in November 1983. But with the demands of the 1983 rate case, the customers agreed with Bonneville to suspend completion of that methodology until March 1984. Bonneville has begun the interpretive rulemaking, which would carry out the congressional mandate of priority access to the low cost Federal power.

However, in a letter dated October 12, 1983, Bonneville suggests that there is a hierarchy of statutory duties, and protection of priority to price is not very high on Bonneville's list.

And second, the letter certainly implies that a rate ceiling such as established by section 7(b)(2) operates only in a power deficit situation, and that, somehow or other, that type of a guideline would not work in a power surplus situation.

So we ask the committee's concern, and I hope you share our concern regading the philosophies that have been adopted in the 1983 rate case, as we go down the road in our further rate dealings with Bonneville.

Thank you, Mr. Chairman.

Mr. **Weaver**. Thank you, Mr. Dyar. Mr. Dyar, you agree that Bonneville has to collect the amount of money that it says in order to pay its obligations, don't you?

Mr. **Dyar**. Yes, Mr. Chairman. In fact, in our opening and closing testimony in the 1983 rate case, we attempted to try to build trust with Bonneville. We went into the rate hearings saying in the opening brief that Bonneville's financial integrity was number one on our list. We were not arguing for lower rates, and we're still not necessarily arguing for lower rates.

Mr. **Weaver**. Well, let me just say that what you're saying, the points you're raising, are not that Bonneville should reduce its charges—I mean aggregate charges. They've got to raise that money to make their obligations. You're just simply raising the question of who pays what share; is that not correct?

Mr. **Dyar**. That is correct.

Mr. **Weaver**. All right. My question, then, is are you satisfied with the law now, or that Bonneville is obeying the law? Or do you think the law needs changing?

Is Bonneville, in your estimation, obeying the law in doing the things that you are protesting against?

Mr. **Dyar**. On the question of being involved in the Exchange costs, the allocation of Exchange cost to the existing preference customers, there, I think, the Administrator is on very thin ice. That's my personal opinion. I'm not a lawyer. I'll quickly make that statement.

I think on the question of his overall treatment, I think that there is an abuse of discretion in the allocation of costs.

Mr. **Weaver**. The people you speak for, the generating utilities, generally feel that Bonneville is exercising too wide a discretion and penalizing certain public utilities by doing so.

Do you think the law needs changing, if no more than just simply tightening it up to take away the discretion from Bonneville, so they'll do what you think they're supposed to do?

Mr. **Dyar**. I haven't discussed that precise approach with the utilities that I'm representing today. I think that that would be something that we'd like to take a look at.

Mr. **Weaver**. What do you think, Mr. Greening? Do you agree with what Mr. Dyar has said?

Mr. **Greening**. I would rather look at it from a pragmatic viewpoint. In retrospect, I think that you would find a great consensus among many of Bonneville's customers that the Regional Power Act was a mistake and that many people wish that they hadn't supported it.

Now that it is in place, the question whether we should amend the act is a much more difficult one, because we're concerned that, once you open the act up, you might get some of the changes that you want, but you might get some other changes that you don't want, and the net effect is that it's worse than it was before.

So I, like Mr. Dyar, have not consulted my group of constituents, but I'm sure that there would be mixed feelings about opening up the act to amendments.

Mr. **Weaver**. Oh, I really wasn't raising that issue. I think that there would be a lot of people who would scream bloody murder at that. I just, in general, wanted to know whether it was Bonneville obeying the law or Bonneville abusing or, in your term——

Mr. **Greening**. I thought you had asked the question, should the act be changed? And that's the question that I was answering.

Mr. **Weaver**. Yes, yes.

Mr. **Greening**. Is Bonneville obeying the law? That question is so general in nature it's almost impossible to answer. We are in court, in some cases contending that they are not obeying the law, and in other cases we are contending that they are.

So I think, there, again, you would find mixed feelings among many of the customers.

Mr. **Weaver**. Well, I would like to hear from Mr. Bidwell of Reynolds Metals Co., because he is going to have to defend his interests, aren't you, sir?

Well, let's hear what the aluminum companies say about this.

[Prepared statement of Richard Bidwell may be found in the appendix.]

STATEMENT OF RICHARD BIDWELL, DIRECTOR, ENERGY RESOURCES, REYNOLDS METALS CO.

Mr. **Bidwell**. Thank you, Mr. Chairman. I have filed already the written testimony, so I'll try to summarize.

As you mentioned, I'm with Reynolds Metals, and I'm the director of energy resources for that corporation.

I think it would be good to emphasize the benefit that the direct service industries provide the region for a background to some of our concerns. We represent some 15 industries that operate 20 plants. We produce approximately one-third of the Nation's aluminum out in the Northwest, 100 percent of the Nation's domestically mined nickel, and other metals and fabricated goods, chemicals and other important products.

At full operation, we employ some 15,000 people. We have a payroll of over $500 million. We contribute about $1½ billion a year to the Northwest economy.

Mr. Weaver. The former Governor of Idaho is one of those employees, is he not, Mr. Andrus?

Mr. Bidwell. He's not on our payroll, as such.

Mr. Weaver. Oh.

Mr. Craig. Mr. Chairman.

Mr. Weaver. Well, I just thought it was good that you were employing unemployed politicians. That's really good. [Laughter.]

Mr. Craig. Would the Chairman allow me to interject something?

Mr. Weaver. By all means.

Mr. Craig. I was uniquely surprised the other night while in the north end of my district, reclining in the quiet of my motel room reading some important papers for the next day, and there was Cecil on the tube. [Laughter.]

I called him the next day and said, you know, "At what price, Cecil? At what price?" [Laughter.]

Mr. Weaver. Well, nevertheless, I like to see you employing all these people, including politicians. It gives me hope. [Laughter.]

Go on.

Mr. Bidwell. Since we're all in agreement that he's done a good job——

Mr. Craig. Oh, it was a marvelous ad. [Laughter.]

Mr. Bidwell. If I may go on, as has already been alluded to this morning, I think Congressman Craig pointed out very well that we are purchasing about 17.7 percent of Bonneville's firm power and paying approximately 22 percent of its revenues. Much of that difference is made up by the Exchange program. Some 2.1 million Northwest residential and small farm ratepayers benefited totally in 1982, and I think the figure is correct, Mr. Chairman, $216 million, I think that is the figure that I heard, and it is an accurate net figure. If it is, then that's what we'll use.

In addition to this rate situation, we are also valuable to the power system itself. We do, in fact, represent reserves for the Bonneville system. And Bonneville has bought rights to interrupt the DSI loads to protect other customers during shortages, while avoiding the need to build backup or reserve facilities.

The ability of the DSIs to continue to provide these benefits is seriously threatened by the higher and noncompetitive power rates. Granted, we expected to see some increases under the Residential Exchange program, but nowhere near to the extent that we have experienced them.

As has already been mentioned this morning, we have seen since 1979 an 800 percent increase in our rates, starting at 3.17 mills and now going to 26.8 mills. This tremendous rate increase threatens to price the Northwest aluminum industry out of the international marketplace.

BPA's rate to the Northwest aluminum industry is 50 percent greater than competitors around the world, at a 17-mills rate, and if we assume that all of the aluminum industries get back to full production, that figure would only be something like 22 mills. We're still not competitive.

An independent study was commissioned earlier this year by the DSIs. The Battelle Pacific Northwest Laboratories in that report estimated that 83 percent of the operating smelter capacity in the world had a lower power cost than we in the Northwest.

Since electricity represents as much as one-third of the cost of producing aluminum, power rates become a very, very significant part of the decision of whether or not we operate or do not operate. And, again, as alluded to earlier this morning, some of the plants in the Northwest have become swing plants. They're going to operate when the economy is strong, and they're not going to operate when the economy softens.

Last year, we saw this dramatically demonstrated, as 55 percent of the capacity was curtailed in the Northwest.

The DSIs have a fundamental, long-term problem. While we can operate profitably during economic peaks, no industry can long survive the cyclical valleys of the marketplace. This is especially true when we're struggling under competitive disadvantages of higher than average basic production and shipping costs. And for us to make the necessary capital improvements that we should to our plants, BPA must develop competitive predictable rates for the DSIs, to remain competitive.

Mr. **Weaver**. One more minute, Mr. Bidwell.

Mr. **Bidwell**. Yes, sir. If I could hurry and summarize, then, the disproportionate rate treatment that we've received threatens the BPA revenues because, actually, BPA is gambling that the economy is going to continue to improve and that, through their imposition of the customer charge which we think is contrary to our contract, they try to threaten us to continue to operate.

Now, BPA has not adequately dealt with the greatest risk, which is entirely within its control, and that's the competitiveness of the DSI rates. BPA must establish a fair, cost-based, competitive rate for its industrial customers, if the agency is to meet its revenue needs and if the Northwest aluminum industry is to continue providing significant benefits to the region and the Nation.

And with your permission, Mr. Chairman, I'd like very much to submit for the record a summary or highlights of the Battelle study which I did not submit earlier.

Mr. **Weaver**. Excellent. We would like to have it. Without objection, it will be placed in the file of this hearing. Thank you.

Mr. Bidwell, I'm pleased to hear you discuss the customer charge and the fact that one of your prime purposes is to provide employment in the Northwest, provide jobs; is that not correct?

Mr. **Bidwell**. That's correct.

Mr. **Weaver**. You want to provide jobs; right?

Mr. **Bidwell**. Yes, sir.

Mr. **Weaver**. Doesn't the customer charge assure that? We have lowered your electric rate now sharply, cut it in half from 23 mills to 12 mills and instituted a customer charge that continues. Doesn't that help ensure that we have jobs?

Mr. **Bidwell**. Not necessarily.

Mr. **Weaver**. Why?

Mr. **Bidwell**. That is a penalty. It's a penalty on top of a penalty, and so it is a——

Mr. Weaver. Well, now, the rate is still the same, Mr. Bidwell. It's just that now, you have to pay that charge whether you're operating at full bore or not.

In other words, it helps us keep jobs in the Northwest, doesn't it?

Mr. Bidwell. By example, such a penalty, or a similar penalty, in the Tennessee Valley Authority is imposed. Those plants have been shut down for some period of time. So a penalty of that nature doesn't necessarily assure jobs.

Mr. Weaver. TVA's overall rate is higher than the Northwest.

Mr. Bidwell. That is correct.

Mr. Weaver. Well, there you are, Mr. Bidwell.

Mr. Bidwell. Excuse me, sir?

Mr. Weaver. I said, there you are. That's the answer.

Mr. Bidwell. But they also have such a penalty charge that, if it's shut down, there is a penalty imposed.

Mr. Weaver. Sure.

Mr. Bidwell. I was just trying to point out that a penalty does not necessarily assure that we're going to continue to operate.

Mr. Weaver. Well, at 81 cents a pound, I think you're doing quite well. I've been reading your profit statements for the aluminum companies, and you are apparently in a much stronger position than copper, certainly. You're really going full bore.

Mr. Bidwell. We trust that we are going to continue to see an increase in that.

Mr. Weaver. I'm pleased to hear that.

Mr. Bidwell. However, in the bad times—if they come again, and I guess that we can expect sometime along the way that there will be another downturn—the plants in the Northwest, because of their being noncompetitive, will more than likely have to be shut down again.

That's the problem. That's the long-term problem that I mentioned earlier.

Mr. Weaver. Mr. Bidwell, well, you probably could go to nice stable countries like Zaire or something like that. It's probably worthwile to stay in the United States; that is the point I'm trying to make.

Mr. Bidwell. Well, we would like to go to Canada and increase our production there in Quebec Province.

Mr. Weaver. Quebec—they've got a lot of surplus up there.

Mr. Bidwell, I have two charts here—indicating. One shows the DSI rate from 1985–95. And then this shows the priority firm rate. This is the Senate report of the Northwest Power bill in 1979. It shows that under, the Northwest Power bill, they projected the DSI rate to always be higher than the priority firm rate.

Bonneville has come in with figures in this year now to show in 1989 or so—1987—that the DSI rate goes lower than the priority firm. That's probably not right. You wouldn't agree with that, would you?

Mr. Bidwell. That could occur. When you take the 7(b) rate as the basic rate for priority firm and for the DSIs, and then with that you have a typical markup, but you also have offsetting that, which might more than cover the markup, the value of reserves and a recognition of the type of load and character of load being served.

Mr. **Weaver**. Your contracts with WPPSS 4 and 5, where you were supposed to buy electricity from WPPSS 4 and 5, are null and void, are they not?

Mr. **Bidwell**. That's true.

Mr. **Weaver**. So you're not going to be paying anything on WPPSS 4 and 5.

Mr. **Bidwell**. No; our contracts with WPPSS 4 and 5 were strictly to take surplus——

Mr. **Weaver**. But the aluminum industry strongly promoted WPPSS 4 and 5 and went so far as to sign contracts to take some of the electricity. Now you're free and clear on WPPSS 4 and 5, while the customers of the prority firm are going to have to—possibly may have to, depending on court cases—pay for WPPSS 4 and 5.

Mr. **Bidwell**. In 1976, WPPSS came to the DSIs and asked, would we or could we take for the early years of the operation, the WPPSS 4 and 5 surpluses, if in fact they were available. And, if we were to do that, it would give them an advantage in obtaining more advantageous financing, and that was really the basis upon which we signed those contracts.

Mr. **Weaver**. The gentleman from Idaho.

Mr. **Craig**. Mr. Chairman, I, trying to sort through all of this, have a better understanding, because I would be the first to admit that this is a field that I have not spent a lot of time with and am at least attempting to develop a working knowledge in.

Mr. Imbrecht, you make a statement in your testimony—oh, excuse me, Mr. Dyar, excuse me—that maybe Mr. Greening's comments alluded to when you make the statement that in the 1983 rate case the Administrator went beyond the statutory bounds placed upon his discretion. In the case of your evaluation that the Administrator has acted in such a way, have you brought suit against BPA for that kind of an action?

I mean, if he's broken the law, which, in essence, you have said by your testimony you feel he has, don't you have a recourse available to you, if in fact he has broken the law?

Mr. **Dyar**. Certainly, we have the recourse.

Mr. **Craig**. What action have you taken, then, based upon this observation or at least this judgment?

Mr. **Dyar**. May I have a moment?

Mr. **Craig**. What?

Mr. **Dyar**. May I have a moment with my counsel here?

Mr. **Craig**. Sure.

Mr. **Dyar**. Well, Congressman, we have brought suit against Bonneville before.

Mr. **Craig**. But have you on this action?

Mr. **Dyar**. On this action——

Mr. **Craig**. Or are you threatening suit, or what is your current status?

Mr. **Dyar**. We have under active consideration the issue of litigation against Bonneville regarding the 1983 rate case. It's under investigation regarding the form and as to what court we may be filing in.

We are in a position of not being able to proceed until the administrative remedy has been cured, and that was only cured yesterday with the FERC report.

Mr. **Craig**. I was going to say, that was going to be my next question, maybe both to you and Mr. Greening, as it relates to FERC's decisions yesterday.

Where does that put you at this time?

Mr. **Dyar**. We haven't analyzed the FERC order. The best I understand it is it sets aside the 1983 transmission case.

Mr. **Craig**. That's right.

Mr. **Dyar**. To that extent, I don't know the impact regarding the 1983 wholesale rate proposal on an instant basis, so we haven't had the time to——

Mr. **Craig**. Can you respond to that?

Mr. **Greening**. Mr. Congressman, I am very confident that all of Bonneville's customers will be in court over the 1983 rate case, whether on the defensive or the offensive. All of the customers have expressed reservations about portions of the rates, and I am confident that the amount of money involved really dictates that everyone will be in court. The last two cases, 1981-82, were both challenged in the Ninth Circuit and also appealled to the Federal Energy Regulatory Commission.

So I suspect the same situation will follow here, regrettably.

Mr. **Craig**. Where is the 1982 challenge at this time, or has there been resolution brought?

Mr. **Greening**. Unfortunately, there is a jurisdictional question raised in the lawsuits with the ninth circuit. Many of the people challenging the BPA rates in 1981-82 raised the question of the scope of FERC's jurisdiction versus the scope of the ninth circuit's jurisdiction. The Ninth Circuit has not yet ruled on that. It asked for a special briefing on that, because we wanted to find out whether we should go to FERC first and then wait until that's all over and then go to the Ninth Circuit, or we should file at the same time on separate issues or file at the same time on all issues.

That jurisdictional problem has not yet been ironed out. And the Ninth Circuit has not only not ruled on that, it has not ruled on any of the substantive issues raised in those two cases, either.

So we're really currently in a state of flux and I suspect because——

Mr. **Craig**. Does not that, though, that problem, that obstacle at this time also, at least as it relates to the 1983 action, and any action that you might take against BPA as to this current rate problem, hinge on that?

Isn't that that gray area that I was talking about earlier this morning as it relates to who has what authority to do what?

Mr. **Greening**. Yes, except that this is not the authority vested in BPA so much as the question of the scope of authority, the scope of jurisdiction vested in an administrative agency like FERC versus an article III court like the Ninth Circuit.

And I'm virtually certain, because we have a 90-day time limit, that starting today, we're going to be counting the 90 days and we'll have to file an action in the Ninth Circuit just to protect our interests, since the Ninth Circuit has not yet told us who has jurisdiction over what.

Mr. **Craig**. I see, OK.

Mr. **Dyar**. Well, Congressman——

Mr. **Craig**. Go ahead.

Mr. **Dyar**. I was going to interject the point, as I stated at the beginning of my testimony, that we weren't here to rehash necessarily the rate case, that this is the Bonneville oversight committee, and as it's carrying out its functions under Public Law 96-501.

Mr. **Craig**. Isn't ratemaking part of that?

Mr. **Dyar**. That's correct, part of that function.

Mr. **Craig**. OK.

Mr. **Dyar**. And I think it's interesting that it seems like every action that Bonneville attempts, whether it's the left hand doing the action or the right hand, that we all end up in the Ninth Circuit Court of Appeals. [Laughter.]

Mr. **Craig**. Isn't all of that relating basically to the escalation of power costs, and I think the basic question that the chairman asked a few minutes ago of who pays what share? Can't you really boil it down in simplistic terms to that? And then, of course, the complication comes as to what formula you devise that you can agree on as to who's going to pay what share of the overall costs of BPA.

Mr. **Dyar**. I think the Congressman has hit upon the right point. I don't think that you've heard any of the various customer classes argue that Bonneville has been derelict in its trying to reduce cost. I think that Bonneville gets a lot of support in that regard. I think that Bonneville gets support in terms of having its rates sufficient to meet its financial obligations.

But beyond there, then comes, you know, the problems of who pays. And Public Law 96-501 sets up some very interesting constraints, and I might—if the Congressman would bear with me—note that the longest standing constraint on the Administrator's discretion as to how he charges his cost to the classes of customers has been the preference and priority clause.

Mr. **Craig**. Let me ask——

Mr. **Weaver**. The time of the gentleman has expired. I've got two more witnesses to go. We must get——

Mr. **Craig**. Mr. Chairman, I won't argue with you. I recognize that I've had 5 minutes and you had 10 minutes a minute ago, and I'd kind of like to have another 5 minutes sometime soon.

Mr. **Weaver**. You get 5, and 5, and 5, and 5, and 5, all the 5s you want.

Mr. **Craig**. My watch doesn't quite keep the same time yours does.

Mr. **Weaver**. I don't have a watch. That's why.

Mr. **Craig**. That's the problem. [Laughter.]

Mr. **Weaver**. I just want to get the other witnesses on, that's all. Bernard Palk of the Los Angeles Department of Water and Power.

Please, Mr. Palk

[Prepared statement of Bernard Palk may be found in the appendix.]

STATEMENT OF BERNARD PALK, LOS ANGELES DEPARTMENT OF WATER AND POWER

Mr. **Palk**. Thank you, Congressman Weaver. My name is Bernard Palk and I'm here from the city of Los Angeles Department of

Water and Power. I want to thank you for the invitation to present testimony to you.

My testimony is submitted on behalf of the municipal utilities of Los Angeles, Burbank, Glendale, and Pasadena. Our four utilities are interconnected municipal systems and serve the Greater Los Angeles Metropolitan Area with a population of approximately 3.5 million people.

We have combined annual sales of about 20.5 billion kilowatthours of energy. The service is rendered to approximately 1.4 million residential customers, as well as 200,000 commercial and industrial customers. Our aggregate capacity is 7,500 megawatts with a 1983 noncoincidental peak load of 5,084 megawatts.

The subjects I wish to discuss relate to, No. 1, BPA's discriminatory operating practices between the two regions and the attendant revenue losses to the Pacific Northwest.

No. 2, problems observed in BPA's ratemaking and FERC's review processes.

No. 3, impediments and incentives to interactions between the Pacific Northwest and Pacific Southwest.

No. 4, recommendations to rectify the problems related to the issues noted above.

First, a brief historical background. Nearly 20 years ago, the major California utilities and Bonneville, along with other Pacific Northwest utilities, agreed to develop and construct two 500 kV AC and one high voltage DC intertie lines interconnecting the two regions. This decision was due to the availability of excess surplus energy which had been initially valued at 2 mills per kilowatthour and the need for seasonal support to the Pacific Northwest which could be supplied by the Pacific Southwest.

This 2 mills per kilowatthour charge for surplus energy appeared to be a reasonable recovery rate for a resource that would have been otherwise wasted by being spilled and lost to beneficial use. Incidentally, oil prices at that time were less than 3 mills per kilowatthour.

The availability of this surplus, which is sometimes referred to as "dump energy," was one of the contributing factors to the economic justification of the intertie lines. We are currently in the process of a further DC intertie upgrade from 800 kV to 1,000 kV. The result of these upgrades is that we will increase the DC intertie transfer capability from 1,440 megawatts to 2,000 megawatts.

Our four cities have a 50-percent ownership entitlement in the DC intertie, which, after the upgrade, will represent 1,000 megawatts.

In calendar year 1982, Los Angeles alone purchased energy from Bonneville Power Administration and other Northwest entities providing approximately $33.3 million for the Pacific Northwest economy.

As to discriminatory operating practices, the sale of nonfirm energy makes a significant contribution, about 8.7 percent projected for operating year 1985, to BPA's total revenue. The operating practices regarding nonfirm sales consequently have a substantial impact on these revenue recoveries.

We believe that BPA operates in a highly restricted and discriminatory manner toward the Pacific Southwest. This includes limiting its nonfirm sales and refusing to offer nonfirm energy which has been declined in the Pacific Northwest to the utilities in the Pacific Southwest.

In our testimony during the 1983 rate hearings, we estimated that BPA's nonfirm operating practices cost Bonneville a potential revenue loss of over $114 million. Also, BPA's proposed 1983 nonfirm energy rate structure will perpetuate the discriminatory practices by, among other things, allowing the same type of energy to be sold to the same customer class at different prices.

If BPA would operate its system in a less restricted and discriminatory manner, BPA could increase its revenue recovery while still observing the requirements mandated by law.

As to problems observed in BPA's ratemaking and FERC's review processes, during our involvement in the 1983 and prior rate hearings, we have observed that BPA provided incomplete and inaccurate studies in support of its proposed rates, gave no opportunity for parties to make oral comments and cross examine BPA staff on changes made following closing of oral presentations, and performed no cost-of-service studies to identify costs incurred in providing nonfirm service.

Furthermore, FERC's review process, which may find BPA's rates to be inappropriate and which may have been placed in effect on an interim basis, does not remedy the problem by ordering either a rate adjustment or a refund to the affected parties.

In the matter of impediments and incentives to interactions between the Pacific Northwest and Pacific Southwest, recent proposals to increase the intertie capacity between our two regions could be impeded by the historic volatility of nonfirm rates, potential intertie access charges that are almost tantamount to anticompetitive practices, inconsistency in BPA's operating practices, uncertainty of nonfirm energy availability to the Pacific Southwest due to expanded sales within the Pacific Northwest, and short-term recall provisions of contracts entered into with the Pacific Southwest.

All of these factors must be taken into consideration when examining the economic justification of a project.

Notwithstanding the above impediments, given the proper incentives, our cities would like to continue to conduct business with and thus, contribute to the economy of, the Pacific Northwest.

Realizing the anticipated abundance of available surplus energy, the seasonal and daily load diversities between our regions, and the prospects of a truly cost of service based nonfirm energy rate structure, there are financial benefits that are available to both regions from continued and increased interactions.

In all of these, then we come to recommendations. In view of the preceding discussion, the cities offer the following recommendations:

No. 1, BPA should reevaluate its operating procedures concerning the timing and amount of nonfirm sales. In particular, a new study should be initiated of the Columbia River Basin, its various reservoirs, dams, and electrical facilities to determine the optimum manner of system operations.

No. 2, Congress should amend statutory requirements such that, once the availability of surplus energy has been declared by BPA, such surplus energy shall be offered first to the Pacific Northwest and then shall be mandatorily offered to the Pacific Southwest on the same terms as was offered to, but declined by, the Pacific Northwest utilities.

We contend that that reason alone was a major factor in Bonneville losing significant revenues last year.

No. 3, as an alternative to No. 2 above, Bonneville should be required to request the Solicitor of the Department of Interior, or Congress should request the U.S. Attorney General, to clarify that portion of Public Law 88-552 concerning surplus energy as to when and by what terms it can or should be exported from the Pacific Northwest region.

No. 4, FERC's final approval should be obtained by BPA prior to implementation of any new rates, including interim rates.

No. 5, that FERC should require BPA to establish rates based upon actual costs incurred to supply energy to each customer class.

And finally, No. 6, BPA should base its entire revenue requirement and recovery on its firm energy sales and utilize any revenue realized from nonfirm sales to offset any deficits or apply as a rebate adjustment to all of its customer classes after its Federal Treasury repayment requirements have been met, or to accelerate payments to the Treasury.

This last, we believe, would provide a very firm and sound basis for rate structure by the Bonneville Power Administration. It would take the guesswork out of their continuing efforts from year to year to predict streamflows, snow falls. It would take the roulette or blackjack or, as some utilities have referred to it, the "craps" out of the guesswork in predicting the energy from Northwest hydro.

On behalf of the cities of Los Angeles, Burbank, Pasadena, and Glendale, I appreciate this opportunity to present our views and welcome any opportunity to answer any questions you may have.

Mr. WEAVER. Thank you, Mr. Palk. I don't think there are any California members on this subcommittee. However, there are on the full Interior Committee.

Is Bonneville offering you any firm energy, or nonfirm energy, right now?

Mr. PALK. We are not buying any energy from Bonneville at present.

Mr. WEAVER. That isn't my question. Is Bonneville offering you any?

Mr. PALK. Bonneville—just 1 second.

No, no; they aren't.

Mr. WEAVER. Would you buy any if they offered it to you?

Mr. PALK. I believe so.

Mr. WEAVER. Why aren't they offering it to you? We've got some, don't we?

Mr. PALK. They're not in the process now of making any offers at all. I believe they had some discussions underway, or they've taken some bids in the last several weeks about some standard rate nonfirm power.

Mr. WEAVER. They're filling the reservoirs, are they not, so that they will be able to spill it next spring. [Laughter.]

Mr. **Palk**. I imagine that, with what happened last year, if that's any precursor, they filled the reservoirs so that they would spill in October.

Mr. **Weaver**. Oh, in October?

Mr. **Palk**. Yes.

Mr. **Weaver**. Excellent.

Mr. **Palk**. That was, incidentally, one of the times that energy was offered in the Northwest at the standard rate, 18.2 mills. Californians were lined up to buy the refused energy, which the Pacific Northwest utilities had refused. Bonneville did not offer it to the Pacific Southwest. And they would have gotten 18.2 mills. It was allowed to spill and we got it at 9 mills.

Mr. **Weaver**. I always told you those guys were good. [Laughter.]

Mr. Dyar, in your testimony, you discussed the availability charge. I asked Bonneville about that. You say:

> Now Bonneville finds itself with surplus power. In this rate case, BPA adopted a new penalty, the availability charge, which we believe violates the new power sales contract provisions. More importantly for this subcommittee is the fact that this is a prime example of Bonneville arbitrarily abandoning the previous long-standing policy and forcing its customers in a totally different direction, availability charge.

Why did Bonneville abandon its long-standing policy? What caused this sudden change, in your opinion?

Your lawyer can answer the question.

Mr. **Dyar**. A small conference. As best we can determine, Mr. Chairman, Bonneville wanted to simply shift the risk of surplus onto the generating public utilities.

Mr. **Weaver**. Well, why isn't this fair?

Mr. **Dyar**. I'm going to ask Mr. Walt Williams of Seattle to respond.

Mr. **Weaver**. Sure.

Mr. **Williams**. Thank you, Congressman. One of the reasons that it is not fair is that Bonneville has such an enormously large system. For a utility to use its own resources on its own load and not purchase 100 megawatts or 150 megawatts of Bonneville power, Bonneville doesn't see that in their system. It's so easily absorbed. But to a utility, that is a tremendous amount of money.

Mr. **Weaver**. You represent the city of Seattle, do you not?

Mr. **Williams**. Yes.

Mr. **Weaver**. What you're saying is that Bonneville has far greater flexibility because of its enormous resources than does an individual utility.

Mr. **Williams**. That's correct. And not only that. The only place we have to sell power is to California, or that is one of the few places that we have to sell it, where we have normally sold our surplus power in the past.

We don't have that access. Bonneville controls the access to California. Now they are controlling the access. They're shifting the surplus to us and then they are penalizing us for not taking the power.

Mr. **Weaver**. You think Bonneville abandoned this long-standing policy, this major change—there's no question about it—simply to raise revenues, or did they do this for other purposes?

Mr. **Williams**. I think it's the first step in taking away some of the rights of the generating utilities. As I understand it, the revenue that would be collected will not be a large amount of revenue. It's a very insignificant amount. But it's one of the things that we feel that we did not bargain away in our power sales contract and that through the rates Bonneville is attempting to impose an additional obligation on us, an obligation that we didn't have before.

Mr. **Weaver**. But if it didn't raise a lot of additional revenue, and it's a major policy change, nevertheless, I still need the insight into why you think Bonneville did it. Major policy changes don't come easily, usually. They must have had a strong motivation.

Mr. **Williams**. Well, as I indicated, they are basically shifting the risk. They will be raising some revenue. And it's taken away the operational flexibility of the smaller utility.

Mr. **Weaver**. Mr. Spigal or Mr. Pollock, I see you in the audience. If you can't give us a good answer, then don't take the committee's time. If you can give us some enlightenment on this, I'd appreciate it.

Mr. **Pollock**. Mr. Chairman, I'm Walt Pollock. I'm BPA's assistant power manager.

The charge or the provisions of the rate that you are discussing were really brought upon by occurrences over the last year where generating utilities shifted a major amount of their load off of Bonneville and met it through other means. It meant a lot of money to Bonneville. We lost a substantial amount as a consequence.

Mr. **Weaver**. You say they bought power from other sources and didn't buy it from you; is that what you're saying?

Mr. **Pollock**. Yes, sir.

Mr. **Weaver**. What were the other sources?

Mr. **Pollock**. Well, they varied. Some displaced firm purchases with nonfirm energy of their own. There were purchases from inter-utility transfers, some purchases from B.C. Hydro.

So there are a variety of reasons why that occurred.

Mr. **Weaver**. I'm trying to decide whether to get into this further. I'll ask one more question and that is: Isn't Bonneville a public agency there to serve these people? Aren't you to serve them instead of be tough on them?

Mr. **Pollock**. Yes, sir, there's no question about that. The issue, I think, is, if we make provisions to serve them and assume revenues in meeting our expenses, and then for whatever reason those utilities find a better deal, find a better opportunity, that causes us a lot of problems. That's the problem we're trying to correct.

Mr. **Weaver**. Well, what you're really saying, I think, is if the generating utilities cost you money, you've got to pick it up from somebody else. And that's unfair to them, really, isn't it?

Mr. **Pollock**. That's right. We are not opposed to utilities meeting their own loads with their own resources. What we are opposed to is when we strike a deal——

Mr. **Weaver**. Moving around.

Mr. **Pollock** [continuing]. Changing the rules in the middle of the game. That's the difficulty.

Mr. **Weaver**. I've gone past my time and I apologize to my friend from Idaho. Let me just give Mr. Dyar or anyone else a chance to rebut Bonneville.

Mr. **Craig**. Yes, go ahead. I'm fascinated by the discussion.

Mr. **Larsen**. Mr. Chairman, Al Larsen. I apologize for my voice. We left a sunny autumn in Oregon and arrived in the rain here several days ago, and I came down with a bad cold.

We offered Bonneville in the rate case several alternatives to take care of its revenue problems, primarily, giving us a reasonable opportunity to market the nonfirm power elsewhere instead of displacing Bonneville firm power with that. As Mr. Williams was explaining, we think that we are pretty much shut out both ways. They want to penalize us for dedicating it to our load, and they are monopolizing the nonfirm market. We are pretty much out in the cold. That's why we think that they have abused their discretion.

They jerk us one way 1 year and another way another year. I don't really want to get into the legal issues that are likely to be resolved in court. I just wanted to call this kind of treatment to the committee's attention.

Mr. **Weaver**. All right. I think you both made your case.

Mr. **Craig**. Mr. Pollock.

Mr. **Weaver**. The gentleman from Idaho.

Mr. **Craig**. Don't leave. I just wanted to ask a question on a followup to what the gentleman from California said as it relates to, I think, you said that this year there was nonfirm power available, that it was refused in the Pacific Northwest, but not offered to you.

Mr. **Palk**. No, this was last year, last October.

Mr. **Craig**. Last October. And I think you said that the companies in the Pacific Southwest were lined up to buy and would have bought?

Mr. **Palk**. That is correct. In fact, among our four utilities, there was miscommunication among us, and one of them did sign up for an 18.2 mills purchase, because we were assured by Bonneville that they had the ability to control any spill and it would never be spilled that hydroyear. The next day they declared spill. Our one partner had to pay that rate for the entire month and our other three utilities had the benefit of the spill rate.

Mr. **Craig**. Mr. Pollock, what is your reaction to that comment? If there was nonfirm power available and the Northwest had refused it, obviously, you're in a tremendous budget crunch. Why didn't you sell?

Mr. **Pollock**. Congressman Craig, it's surprising how two different people can interpret events in such a different fashion. I remember the period of time that Mr. Palk is referring to. My recollection of events at that time is that we were offering nonfirm energy in the Northwest at the standard rate, 18 mills a kilowatthour. It was being purchased by Northwest utilities, and that is the sequence that we go through in offering nonfirm. First offer it in the Northwest, and then, if it's not subscribed to, offer it in the Southwest.

I'm not aware of any——

Mr. **Craig**. So your argument is that it was offered and not refused. It was purchased.

Mr. **Pollock**. My recollection is that during that period of time, Northwest utilities were purchasing about 1,000 average megawatts of nonfirm power from Bonneville. They were then marketing other resources on the Intertie to the Southwest.

So we might want to go back and look at those days and months.

Mr. **Craig**. Yes.

Mr. **Pollock**. But that is my recollection of events at that time.

Mr. **Craig**. Well, let me get out of an area——

Mr. **Weaver**. Would the gentleman yield?

Mr. **Craig**. Yes, sure.

Mr. **Weaver**. Weren't they actually trying to buy it from you and then resell it to California, and if they couldn't resell it to California, they didn't buy it from you?

Isn't that really what was going on? As I recall, that was the situation.

Mr. **Pollock**. Well——

Mr. **Weaver**. Weren't they trying to peddle a markup? The reports that I got at the time were that.

Mr. **Pollock**. Well, I'm sure that they were running and marketing resources of their own to California at higher prices than the nonfirm energy that was being offered to them. So I think that that interpretation of events is probably correct.

Mr. **Craig**. Mr. Chairman, can that happen? The gentleman from Seattle said that BPA blocked the access.

Mr. **Pollock**. Now I am not familiar with any instance where Bonneville has refused to schedule nonfirm energy for a public generating utility. I have absolutely no idea what he was talking about.

Mr. **Craig**. OK.

Mr. **Palk**. Sir? May I make a comment?

Mr. **Craig**. Yes, please do.

Mr. **Palk**. In specific testimony that was submitted during the BPA rate case, we cited the dates when the nonfirm energy was offered to the Northwest. It was not fully subscribed. It may not have been declined, but it was not fully subscribed.

That was not offered to the Pacific Southwest. And, indeed, on the dates toward the end of September of last year, we were negotiating to pay, and these people were lined up to pay, 28.4 mills. We were talking about the higher firm rate energy.

That's when the spill began occurring, within a week.

Mr. **Craig**. Let me leave that and go back to another point that I was interested in this morning, and I remain interested in it as it relates to Mr. Bidwell's comments. I know that when I used the word "subsidy" this morning, the Administrator moved very quickly away from that and chose to use another word, which I guess, under any scrutiny, basically still came back to a matter of semantics.

You mention in your testimony a level of use versus a level of pay and that, in fact, that your level of pay is higher than use, and that that forms a subsidy for other utilities.

Would you go into that a little bit for me, as a matter of information, because it seems significant to me when we're sitting here arguing—or if we aren't, someone else is—who ought to be paying what.

Can you discuss that with us in a little more detail as to how it is a perception of the DSIs?

Mr. **Bidwell**. Yes. Of course, the Regional Act provides that the DSIs will, in fact—I also use the word "underwrite," subsidize——

Mr. **Craig**. I recognize that, yes.

Mr. BIDWELL. It's a difference between the IOUs and the public utility district rates to gain parity within the region for those two rates. That's what I'm mentioning in my testimony. That total in 1982 amounted to some $216 million, and primarily that was underwritten by the DSIs.

So that that has represented much more than we had anticipated when the act was under consideration and even when it was passed. But we, at that point, were looking at the experts that had projected what those rates would be, and they have gone up tremendously.

Mr. CRAIG. Have you basically, based on that formulation and the current rate issue, projected what you might pay in 1984?

Mr. BIDWELL. Beyond the new 20-month rate?

Mr. CRAIG. Yes.

Mr. BIDWELL. I have not.

Mr. CRAIG. Will it be substantially more or less? Do you know?

Mr. BIDWELL. I'm not really sure. I would assume it would be more. But substantially, I'm not sure.

Mr. WEAVER. Would the gentleman yield?

Mr. CRAIG. Yes, I'd be happy to, Mr. Chairman.

Mr. WEAVER. My next question followed on yours. Mr. Bidwell, are the DSIs, under the Regional Act, in your opinion, entitled to post-1985 rates that are lower than the priority firm rate?

I'll repeat that question: Are the DSIs, under the Regional Act, entitled to post-1985 rates that are lower than the priority firm rate?

Mr. BIDWELL. I believe, as I mentioned earlier, that with the adjustments that are made, both up and down, the up being the typical markup, the downward side being the value of reserves and also the recognition of the load characteristics, it is possible under the act for the DSIs to have a lower rate—either at or lower.

Mr. WEAVER. Mr. Dyar, do you think so?

Mr. DYAR. I think the mathematical or computer modeling could perhaps get you there. But I think the political facts of the matter and the deliberations and negotiation on 96-501 were different. But I'm not sure that that was the understanding, because, while I share Reynolds Aluminum Co.'s shock at the magnitude of the rate increases since the passage of 96-501, appendix B to the legislation foresaw a 7 mills rate for the publicly owned utilities, and Bonneville has adopted a final rate of 22 mills. The appendix B foresaw a 21 mills DSI rate. And the DSI rate is 26.8 mills, as proposed by Bonneville in the final rates for 1983.

Mr. GREENING. Mr. Chairman, if I may offer a brief comment of my own also. I'm very concerned, after Congressman Craig's questions this morning to Bonneville and his questions this afternoon, that the committee may be left with a misimpression of what's going on here.

It's obviously sometimes difficult in this formal setting to get all of the information out.

I must regretfully disagree with some of the things that Mr. Bidwell has said. I like him very personally, but right now we are figuring out—we have decided on the size of the pie. Who's going to get what slice?

Historically, from 1940 to 1981, the direct service industries of Bonneville took 39 percent of Bonneville's power and paid 32 percent of the costs. For 41 years, they were subsidized by other customers.

The situation has reversed.

Mr. CRAIG. On a nonfirm basis.

Mr. GREENING. Total costs versus total power take, I'm talking about.

Mr. CRAIG. I was talking about the condition on which that was taken——

Mr. GREENING. Oh, no, no, no, no. Until 1975, it was totally firm power.

Mr. CRAIG. It was firm power?

Mr. GREENING. Yes; until 1975. The conditions changed after 1975 and they have essentially gotten—Mr. Bidwell is concerned about that answer, but let's put it this way: They have essentially gotten totally firm power over most of those years. I don't think that he would disagree with that. The provisions of the contracts changed after 1975.

The important thing now is that the direct service industries have a problem. The problem has been created mainly by the Regional Power Act in the requirement that they subsidize the residential users.

So now the region has a problem. And I agree with Mr. Bidwell. We can argue about the past. We have a different view of the past than they have. The point is, what are we going to do about the future?

We believe that, in the present rate case, the rate is at a level which allows them to operate profitably, as Mr. Weaver pointed out, for the next 20 months. So during the next 20 months, I believe this region must decide what we're going to do about the DSI loads.

We think that there are three options. One is we can make them pay the cost of the power used to serve them and, eventually, that is going to lead to the swing plant situation and probably some of the plants shutting down permanently.

The second option is—and the DSIs disagreed with this testimony, of course—but we can subsidize their rate to make them more competitive. If it is in the national interest to have this aluminum capacity in the Northwest, then it should be the Federal taxpayers that undertake that obligation, not the regional ratepayers.

We cannot take on the obligation of making their rates competitive with 17 mills per kilowatthour in the rest of the world where their rates are subsidized, for example, in Ghana and Australia.

The point is, I think, that maybe there's a third option, and I haven't discussed this with any of my constituents, but it could be possible for Bonneville to offer a low incentive rate, a lower incentive rate to a direct service industry, in return for an agreement by the direct service industry to return the power to Bonneville to back off its contract demand when Bonneville needs the power off in the future. That may be a tradeoff in which both the preference customers and the direct service industries benefit.

I haven't talked with any of them about this. I'm just giving it as an example of the need to look for creative solutions to resolve their problem, which is a regional problem.

Mr. CRAIG. Mr. Bidwell, do you wish to comment on that?

Mr. BIDWELL. May I respond? Number one—and only briefly—the modified firm contract that we operated under before, the then interim contract, and finally, the new 20-year contract, did, in fact, have 25 percent of its amount subject to interruption at any time for any reason. So we did not have totally firm power.

As a matter of fact, it was interrupted for periods of, say, 4 months annually because of water flow. We were able to buy replacement energy at higher cost and continue to operate. That's one problem.

Under the present contract arrangement, the new 20-year contracts, basically three-quarters of our power is subject to interruption of some degree. The top quartile is still subject to it for any reason at any time. The other two quartiles are subject to interruptions, depending on resources not being built in a timely manner, and so forth.

Essentially, only the last 25 percent is substantially firm. So there is a difference in quality of power that the DSIs take as compared to other customers, the preference customers.

And as far as the subsidy, as I put in my testimony, we're not asking for a subsidy. We think cost-based rates will come out where they will be competitive. We are not naive enough to think that Bonneville could, under its present requirement for revenues, to offer us, say, a 17-mill rate. But what we're asking for, what we did ask for and we're continuing to, is, within the discretion that Bonneville has, to develop a competitive rate, one that can put us in the world market where we can compete in the world market, where our commodity is sold.

Mr. CRAIG. Thank you.

Mr. GREENING. Well, we're always going to have a disagreement here, but in the rate case they suggested that they would have a 15-mill rate and we would pay a 26-mill rate. They are required by law to subsidize the Residential Exchange. They have to subsidize it.

So the option of cost-based rates is not even there.

Mr. CRAIG. I see. OK. Well, thank you very much. Mr. Chairman, I have one other question of Mr. Dyar, if I might ask it.

Mr. WEAVER. Sure.

Mr. CRAIG. Your relationship with Bonneville Power, of course, is longstanding. What has over the past several years been the result in rate increases because of this association?

Let's take the 6-year timespan that we're talking about in which Mr. Johnson today agreed that DSIs had experienced approximately a 1,000-percent increase and people like yourself had experienced about an 800-percent increase.

How does that relate to an actual customer charge increase over that period of time? Because of the complications that were involved in trying to explain the difference this morning in the blending of certain types of power, could you come up with a percentage figure?

Mr. Dyar. Well, Congressman Craig, what I'd be very happy to do is to actually send it to you later and submit it for the record later on the actual detail, because I don't have the information in front of me to give you any type of accurate—wait a minute. I'll find it here. [Pause.]

Whereas before, Bonneville under the Project Act was only required to adjust rates once in 5 years, in 96-501 it can't be less than once in 5 years but can be every 12 months.

Our rates, for example, in residential—I can give you the industrial rates as well. We serve some very large industrial accounts, which is a whole separate argument as to the economic base of the Northwest, but we won't get into that one. The residential rate basic charge went from $8.60 to $9.60, which was a 12.4-percent increase. The energy charge went from 2.95 cents to 3.38 cents per kilowatthour.

OK, that's only in the 1 year.

I can't recall what the rates were in 1977, but traditionally, our utility—we could probably figure it out, Carol, if you've got the calculator—we've traditionally run barely about 1 cent per kilowatthour higher than the Bonneville rate for all of our distribution system, payroll, you know. Our utility-associated cost has been 1 cent or less.

Mr. Craig. Are you saying, then, basically, that you track similar to Bonneville?

Mr. Dyar. Yes, we do.

Mr. Craig. So the price would be similar, the rate of increase over that period of time?

Mr. Dyar. Right. The nongenerating publics, their overhead costs, while I'm speaking for Central Lincoln PUD and I'm familiar with a couple of other utilities' operations, have traditionally stayed at right around a cent for all the utilities over and above just what the base wholesale power rate per kilowatthour.

Mr. Craig. It's basically been a passthrough plus cost.

Mr. Dyar. Yes. For example, then, if that's the case, our average annual increase has been in the magnitude of 40 percent on an annual basis since 1977.

Mr. Craig. OK.

Mr. Dyar. I can give you more detailed information.

Mr. Craig. I would be interested in that. It's a great concern, I think, of all of us, you know, the cost factors that we're all dealing with at this moment, whether it's you folks or the DSIs. And, of course, I have some non-generating publics in my area.

Mr. Dyar. Correct.

Mr. Craig. And they're experiencing these kinds of charges with great concern at this moment.

Mr. Dyar. Yes.

Mr. Craig. And rightfully so. Thank you.

Mr. Weaver. Thanks very much. Mr. Bidwell, does your company or the aluminum industry like the Northwest Power Act? Do you think it's a good idea, a good deal? [Laughter.]

Mr. Bidwell. The pause was one of indicating a difficulty in answering that question. It has features that we do not like. It has features that we do like. I think Mr. Greening mentioned earlier that our concern about changing it is because of what we might consider problems with it represents maybe more danger than what we now have.

Mr. Weaver. But, at least as a very intimate player in the Northwest Power Act, the aluminum industry was in at the conception and at its conclusion and was to my mind, the most powerful lobbyist for the bill.

What happened?

Mr. Bidwell. Well, it was absolutely necessary for us to have a long-term presence in the Northwest. That was the only way that we could get new 20-year contracts. No question about that.

What has gone wrong, if that's the way we're to characterize it, of course the costs have gone up. They have gone up way beyond what had been estimated. I don't care what percentages we talk about.

Mr. Weaver. Why have the costs gone up, mainly?

Mr. Bidwell. Well, some of them are the cost of Bonneville, some of it has to be with the Exchange costs, which relates to the increased cost of the investor-owned utilities.

Mr. Weaver. But the major reason is——

Mr. Bidwell. And absolutely, WPPSS costs.

Mr. Weaver. The major reason is WPPSS, right. Right?

Mr. Bidwell. I think it's all three.

Mr. Weaver. Well, I don't understand why people are so afraid to say what the facts are. It's very simple. I mean, we've got the facts here. Let's just take 1979, when Bonneville's costs were $316 million. Total, total costs of $316 million. WPPSS was zero.

In 1984, it's $2.150 billion, and of that, half of it almost is WPPSS—$900 million.

Now the other thing that you say is so horrible is the Exchange cost. About half of my constituents are benefiting from that Exchange cost, and it is is $236 million.

Now, if you were faced with the statistics elsewhere, Mr. Bidwell, wouldn't you just, without hesitation, say, "Oh, my God, WPPSS is by far the greatest. It's three times as great as the next one."

And yet, you couldn't say it, could you? You just couldn't say it.

Mr. Greening. Mr. Weaver, I will say it. WPPSS has been the major cause of BPA's cost increases. Now I ask you a question. What are we going to do about it, now that we have established that as a fact? That's really what this hearing is all about, isn't it?

Mr. Weaver. Well, tomorrow will be, because the mindset is still the same among the utility industry. They want to go ahead and spend more billions of dollars on WPPSS. And tomorrow we're going to go into that.

I just keep saying the same thing that I have said for 11 years. Every day for almost 4,000 days I've said the same thing: Please don't spend another penny. Not 1 more cent. And I've said that every day for 11 years.

And I'm going to continue saying it.

Mr. Greening. With your morning prayers?

Mr. Weaver. And then, what gripes me is that the people who perpetrated this debacle, this fiasco, this absolute just incredible mess, ask me what I'm going to do about it. And I resent that. I resent that. I really do.

But the reason I point this out, Mr. Bidwell, is that we have been reviewing old hearings in this subcommittee, or the subcommittee in charge of Bonneville, back through all of these years. And at the time, 8 years ago, I was saying, for gosh sakes, our electric costs are going to quadruple. As a matter of fact, I told the aluminum company presidents, Edgar Kaiser and a number of other presidents at one hearing about 6 or 7 years ago, I said, "Don't you understand that if you build these plants, your costs are going to go up?"

Oh, no, no, no, no, they weren't. And I said, the only way—and this is a quote—"The only way, Mr. Aluminum Company President, that you are going to keep your costs low is through conservation and not use as much."

The aluminum companies just went hellbent—No, we've got to have these plants. And they used their political clout to push them through.

Now do you expect much sympathy from me?

Mr. Bidwell. Not under those circumstances. However, I think you're addressing, are you not, Mr. Chairman, WPPSS 4 and 5? Or are you, in fact, addressing——

Mr. Weaver. The whole thing, the whole ball of wax. As to WPPSS 4 and 5, the question, Mr. Bidwell, the public utilities are not paying that debt service now, are they?

Mr. Bidwell. They are not, that's correct.

Mr. Weaver. Well, that benefits the aluminum industry, does it not, at least after 1985?

Mr. Bidwell. It dosen't make any difference.

Mr. Weaver. Oh, it doesn't? Or you haven't found it out yet?

Mr. Bidwell. Unless there is some legislation passed or some type of regionalization, WPPSS 4 and 5——

Mr. Weaver. What is the test in the Regional Act for your rates after 1985?

Mr. Bidwell. To be the price for industrial customers by preference agencies.

Mr. Weaver. Right.

Mr. Bidwell. Plus a typical markup with the adjustments.

Mr. Weaver. That's right. The price of industrial customers by the public utilities, served by the public utilities; right?

Now, if the public utilities have to pay for WPPSS 4 and 5, that price is going to go up, isn't it?

Mr. Bidwell. That could be.

Mr. Weaver. You hadn't thought of that, had you? It would mean several hundred million dollars a year to you. So maybe you ought to think about that, because if WPPSS 4 and 5 liability is reimposed, then your prices, your costs are going to go up.

I'll send you a bill for that advice.

Mr. Greening. Mr. Weaver, Mr. Bidwell didn't have in front of him the act, and I think your statement and assumption is incorrect. In fact, section 7(c)(1)(B) requires that those rates of the DSIs be set to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region. But the way that is calculated is that it is based upon the Administrator's applicable wholesale rates, the Administrator's wholesale rates to such public body and cooperative customers, and the typical margins included in the retail industrial sales.

Mr. **Meek**. So WPPSS 4 and 5 have not been included as part of the typical margins charged by the regions publicly-owned utilities to their customers. They would have had the rate that they pay to Bonneville. They would have had to mark up the power to their customers in order to cover WPPSS 4 and 5 debt service if the debt were reimposed.

Isn't it reasonable to think that that would be included in the term "typical margin"?

Mr. **Greening**. Yes, that's true. But Chemical Bank has eliminated that liability. Correct?

Mr. **Meek**. For the time being. I'm sure you'll agree with that.

Mr. **Weaver**. But the question was if it were reimposed. That was the whole point.

Mr. **Greening**. I misunderstood the question. I'm sorry, Mr. Chairman.

Mr. **Meek**. But the potential dilemma that seems to be developing is that, for the next few years at least, the publicly-owned utilities won't be paying WPPSS 4 and 5 debt service. So they won't pay WPPSS 4 and 5 debt service for 1985, 1986 or 1987, perhaps.

At that time, Bonneville's rates for the industries will be based upon its rates to the publics, plus the typical margin that doesn't include WPPSS 4 and 5 debt service.

Then, the securities fraud cases will either be settled or come to judgment. And let's just say that they come to judgment against the publicly owned utilities, who are then faced once again with WPPSS 4 and 5 debt service cost. In the meantime, Bonneville would have been selling energy to the industries without including the WPPSS 4 and 5 debt service as part of the typical margins.

So the publics will have that cost reimposed upon them. The DSIs will have enjoyed a rate discount for those years. And there doesn't seem to be any mechanism for the DSIs to rebate that money back to Bonneville. That is, the Chemical Bank decision has definitely helped the industries of the Northwest. Otherwise, their post-June 1985 rates would be higher.

If liability for WPPSS 4 and 5 debt is reimposed on the public utilities of the region, the 88 participants in WPPSS 4 and 5, that will apparently not reimpose the liability on the DSIs.

So if there's any beneficiary to the Chemical Bank decision in the region, it appears now to be Bonneville's industrial customers.

Mr. **Greening**. Among others. May I ask what the point is?

Mr. **Meek**. Well, I think the question is whether that's an equitable result.

Mr. **Greening**. Well, presumably, without getting into the details, but if the obligation were imposed subsequently, the Chemical Bank decision reversed or securities fraud liability imposed on the public utilities and that were included in the margins, that cost would be spread over the rates from that point on, and, presumably, the margins would then pick it up in that way.

Mr. **Weaver**. There still would be money lost for several years, but that's a good point, Mr. Greening.

Mr. Wenner, would you give us your remarks, please?

The other panel may be excused. Thank you so much.

Mr. Bidwell, before you go, I just want to say that it frequently sounds as if I oppose the aluminum industry. I do not at all. You produce an extremely valuable product, one essential to our economy and national security. I want to keep you running. And I want the jobs in the Northwest. I just have always strived for some form of equity and occasionally, my emotions get going on me as well.

Thank you very much.

Mr. **Bidwell.** Thank you, Mr. Chairman.

Mr. **Weaver.** Mr. Wenner.

STATEMENT OF SEYMOUR WENNER, HEARING OFFICER, BPA 1983 RATE CASE

Mr. **Weaver.** Mr. Wenner, I'm told that you were the hearing officer in the Bonneville Power Administration 1983 rate case and that the people involved have said that you did an excellent job. I want to thank you. It's a very difficult task, and I compliment you for receiving these accolades.

Mr. **Wenner.** Thank you, sir. Mr. Chairman, I submitted a written statement yesterday. I presume you have that.

Mr. **Weaver.** It isn't very long, if you'd like to read it.

Mr. **Wenner.** No, I can be even briefer. Thank you.

I received the request of the committee with some trepidation, because I was the hearing officer in a proceeding which is touched upon by this inquiry. But the question really addressed to me concerned the process rather than substance, so I felt that the inquiry, the request, was proper. My respect for the committee, in any event, would have impelled me to come.

I should observe at the outset that there's a certain just retribution in this situation in that the hearing officer is being given perhaps a dose of his own medicine. [Laughter.]

The gist of the bill which is an issue here, H.R. 3177, is that the hearing officer should issue an initial decision. And I will address my comments to that.

First, the Bonneville rate situation is unique in ratemaking. It is a hydro system and its fuel, in contrast to other utilities, water, is uncontrollable and uncertain. In the normal utility, if you invest a certain amount in the gas, oil or coal input, you can expect that the output will be a function of the input.

In the case of Bonneville, what hit me the strongest when I first began the proceeding was that the fuel is in the hands of God. It depends upon the rain and the snow and the Canadian Rockies. This makes costing very difficult and predictability very difficult.

Again, there are statutory complications which are unusual. Aside from the preference provision, for example, there is the Exchange provision and the requirement that the rates for the DSIs be based upon the net cost of the Exchange.

There are, of course, the normal forecasting and projection difficulties, and these are standard in ratemaking. But I want to suggest first that Bonneville is unique and difficult.

Second, it's a very big proceeding. The hearing officer was completely occupied just in running the hearing and supervising the procedural aspects of it. It was a taxing proceeding—fascinating, interesting, but very taxing. I won't go into the details of the hearing. You're all familiar with those.

I do want to suggest that, if a hearing officer were to write an initial decision in such a proceeding, it would take a very long time. I pondered about this the last few days, and my best guess was that it would be a minimum of a year before he could issue a decision, an initial decision.

Whether the dynamics of the Northwest system could stand still for a period of 1 year after the decision, to be followed by a review later by the Administrator, is doubtful, in my opinion.

I would add a few specific comments about the provisions of H.R. 3177. Those are in my written submission.

But I would suggest that you should not define in a period, say, of 30 days, 60 days, or any particular number, the period in which the Administrator is to review the initial decision and issue a final decision. My experience is that, first, this is too short, given the type of case that you face. But, second, prescribing this, a rigid timetable, puts an enormous burden upon the reviewing authority, in addition to all the problems they have in reviewing the decision.

I think the reviewing party has to have a certain amount of flexibility to carry out the task properly. And I would suggest that you not impose any particular period for the Administrator, and, of course, you haven't for the initial decision, although you said as expeditiously as practicable.

I think as expeditiously as practicable for the initial decision is much longer than anybody would imagine who hasn't been through that operation of presiding over such a hearing.

If I can help you in any other way, I would be glad to.

Mr. **Weaver**. Thank you, Mr. Wenner. You, I assume, have a great deal of experience with other utility regions and utilities themselves. Is the Bonneville Power Administration rate methodology more complex than other areas and States?

Mr. **Wenner**. I think the problems that Bonneville encounters are.

Mr. **Weaver**. Excuse me?

Mr. **Wenner**. I think the problems that Bonneville encounters are more complex and difficult than for others.

Mr. **Weaver**. How about the rate methodology? There are adjustments on adjustments on adjustments.

Mr. **Wenner**. You meet those in every rate case.

Mr. **Weaver**. You do? How about all utility rates? Could they be simplified? Are we building up like the Medieval schoolman?

Mr. **Wenner**. Yes.

Mr. **Weaver**. Worrying about how many angels can stand on the head of a pin, and not getting back to more simple pricing systems?

Mr. **Wenner**. I've——

Mr. **Weaver**. And put you out of a job. [Laughter.]

Mr. **Wenner**. I have thought about your question a great deal, Mr. Chairman, and I think myself and other administrative law judges have wondered about that. The problem is partly finality.

There is no way to divide the pie up so that everybody is happy.

Mr. **Weaver**. Exactly.

Mr. **Wenner**. And the ingenuity and genius of lawyers, accompanied by skilled technical assistants, is such that there is no way that anyone will—plus our legal system—there is no way that anybody will accept what has to be, in some cases, arbitrary decisions—look, this is it and I don't want to hear any more. This is the best I can do.

Mr. Weaver. Yes; that's exactly the situation as I see it myself. No matter what the rate system, everybody is going to think that they are getting the short end of it, and they are going to protest as much as they can and find weaknesses and inequities in it, which is what you're saying

So, I guess it continues. Well, that's valuable testimony to know. Very valuable.

Does the gentleman from Idaho have questions of Mr. Wenner?

Mr. Craig. No; I'm fascinated by his comments, Mr. Chairman. I think sometimes we, and those of us in this committee, forget God and reality all at the same time. And of course that's the uniqueness of a hydro system and the uniqueness to the Pacific Northwest, in particular, with their hydro systems.

I'll read your testimony as it relates to the legislation. I have watched this legislation, or at least was interested in it in its initial phase for those very reasons. It didn't really face up to reality. It tries to change reality to law, and in this case, is probably almost impossible to do, based on the problems encountered.

I thank you for your testimony.

Mr. Wenner. Thank you, sir.

Mr. Weaver. I, again, thank you, Mr. Wenner. I will say on your comment about Bonneville, there's no question about it. The amount of rain and snow have a great deal to do with it. But, on the other hand, there are enormous demand fluctuations—the coldness of the winter and the warmness of the winter. As a matter of fact, if we have a warm winter in the Northwest, Bonneville probably will not make those revenues that they hope to make.

Mr. Wenner. Yes.

Mr. Weaver. And if we have a cold winter, they might. So you don't know.

But in other areas, we not only have those similar fluctuations in demand, but also supply. You can have a Three Mile Island go out and GPU be without two large generating plants that they expected. I was down in Florida last Christmas when two nuclear plants went out and the lights went out for a day. Actually, geothermal probably is the most secure. Nature keeps pumping that steam out. But you can have the Arabs cut off our oil, Iraq may mine Kharg Island tomorrow, and we'll be in trouble with the oil.

So there are problems everywhere, so it's not completely unique to the Northwest, the fluctuation because of the water.

Thank you very much, Mr. Wenner. Anyone has 10 legislative days to submit written testimony.

With that, the hearing is adjourned until tomorrow. The hearing will be in 1310 Longworth.

I would just simply like to close by saying that the investor-owned utilities declined to testify today. I'm sorry they did.

[Whereupon, at 4:30 p.m., the hearing was adjourned.]

BONNEVILLE POWER ADMINISTRATION [BPA] RATES AND RESOURCE PLANNING

FRIDAY, OCTOBER 28, 1983

House of Representatives,
Subcommittee on Mining, Forest Management,
and the Bonneville Power Administration,
Committee on Interior and Insular Affairs,
Washington, DC.

Mr. **Weaver**. The Subcommittee on Mining, Forest Management, and the Bonneville Power Administration will be in session.

I again welcome the public, the press, witnesses, and my fellow Members of Congress to these hearings of the House Interior Subcommittee on Mining, Forest Management, and the Bonneville Power Administration. Yesterday we focused on BPA revenue, repayment, rates and ratemaking. Today's subjects are the cost-effectiveness of resuming construction of WPPSS 3 and BPA's implementation of the conservation features of the Northwest Power Planning Council's 2-year action plan.

At a hearing of the Subcommittee on Water and Power Resources 6 years ago—December 1977—leading up to the eventual enactment of the Regional Power Act in 1980, I stated that the region did—

> not need to rush into construction of extremely costly plants that will saddle citizens of Washington, Oregon, Idaho, and Montana with sharply higher electric bills.

I said:

> We have time to carefully study how to solve our energy problems, not just finance a crash program for disaster. There is enough electricity now for everyone, if we marshal our resources carefully.

I said then that electricity rates will go way up to finance nuclear projects that would turn out to be extremely expensive. I noted that:

> Nuclear powerplants, for instance, are 10, 20, 30 times as expensive as existing power sources in the Northwest. That is not 10, 20, or 30 percent more. That is 10, 20, or 30 times as expensive. So our rates are going to go up. The only way we can assure the cheap rates is to conserve to keep our whole rate structure down. It is going to hurt our economy badly as these rates go up and we are saddled with plants we may not even need.

Six years ago WPPSS had sold only $1.8 billion in bonds and had spent even less on its nuclear projects, since WPPSS was holding several hundred million dollars for future outlays. At that time BPA and WPPSS estimated that it would cost only another $1.6 billion to finish WPPSS 1, 2, and 3. By mid-1982, however, WPPSS had sold $8.4 billion in bonds for its nuclear projects. Now that money has all run out, and Wall Street will not buy any more WPPSS bonds.

It will cost at least another $4 billion to finish WPPSS 3 and 1. The cost of constructing WPPSS 2 and preserving WPPSS 3 is now being paid directly by BPA ratepayers, who are also paying over $800 million per year to WPPSS bondholders.

In the meantime, BPA has repaid essentially none of the $8 billion Federal investment in the Northwest power system since 1979, when payment of WPPSS debt service began.

Since BPA halted construction on WPPSS 3 last May, the Northwest investor-owned utilities that own 30 percent of the project have tried everything, including lawsuits and the introduction of a rider to the Interior appropriations bill by Senator McClure, to get construction resumed. I can understand why they have taken this position. Until the plant is completed and operating, Oregon law provides that Portland General Electric and Pacific Power & Light—owners of 20 percent of WPPSS 3—cannot charge ratepayers for the $400 million they have already sunk at Satsop.

I offered these utilities an opportunity to present their case for continued construction of WPPSS 3 at this hearing today, but they all declined to participate. Their reason is that the potential restart of WPPSS 3 is now the subject of litigation. But the cost-effectiveness of WPPSS 3 is an economic issue, not a legal one, and the pendency of litigation will not prevent BPA from presenting its findings to the subcommittee later today, even though BPA is a party to the same litigation.

What has surprised me is that the Northwest Power Planning Council members and staff have also been proponents of restarting WPPSS 3, even before completing their cost-effectiveness study. Several weeks ago the Council was invited to appear at this hearing and present a status report on their study efforts and any preliminary or final conclusions. This invitation was accepted, until late last Friday, when the Council informed us that it would not appear.

The Council released its issue paper on WPPSS 3 this week on Wednesday. The Council will not vote on its recommendations regarding WPPSS 3 until next Tuesday, but we are interested in the conclusions of the study, not the Council's vote. Despite our requests, the Council has failed even to provide a copy of its issue paper to the subcommittee. Last night, however, we obtained a copy of it from BPA.

Now I understand why the Council was so reluctant to attend this hearing. For months Council members and staff have been stating at meetings throughout the Northwest that completing WPPSS 3 would be cost effective. The Council's vice chairman stated in Boise on September 22:

> We don't want to experience the consequences of not getting on with it (building WPPSS 3) quickly.

The staff director of the study added:

> There would be a very small savings if we delayed the project, but it would be a very large cost if we lost the plant later. It's probably prudent to move right ahead with construction.

Northwest newspapers have featured these and other statements from the Council favoring restart of WPPSS 3. But now, thanks primarily to the critiques of earlier Council work by analysts such as Jim Lazar, the issue paper released Wednesday shows that rapid restart is not cost effective. Even if we assume that WPPSS 3 construction can be financed at a real interest rate of only 3 percent, which is about 7 points of interest less than the current real yield on WPPSS 3 bonds, the study concludes that delaying restart for 3.5 years and completion by 5.5 years would save the region just about $350 million in 1981 dollars. And if realistic interest rates were assumed, it would cost $240 million less to terminate WPPSS 3 immediately and develop other resources than to restart construction now.

Although I find these conclusions fascinating, I certainly do not endorse the accuracy of the Council's study; I believe it probably underestimates the cost of completing WPPSS 3 by several hundred million dollars. It also totally ignores what BPA has now termed the most expensive scenario of all—immediate restart of WPPSS 3 followed by termination later, for whatever reason.

The Council's study concluded that the risk of losing the plant following an extended construction delay is very remote—in the range of 0 to 5 percent. But the Council did not address the probability that WPPSS 3 would never be able to operate even if additional billions of dollars were spent on construction.

I also note that the Council issued its study on October 26 and established a November 1 deadline for written comments. Even with the fastest possible delivery service, that leaves 2 working days at most for interested persons to evaluate and comment upon this report, which is the first written documentation of the WPPSS 3 study ever issued by the Council. I find this out of character for an organization that prides itself on public involvement.

BPA issued its own report on WPPSS 3 cost effectiveness yesterday. We have not seen this study at all, but BPA has provided an expert to present the analysis this morning. The report concludes that a 3.5-year delay in restart of construction would be both prudent and less costly than earlier restart. And, unlike the Council, BPA recognizes the course of action with the most adverse regional result is one where construction continues at a rapid pace but later events result in project termination.

I believe that near-term restart of WPPSS 3 would merely siphon off any remaining funds or dedication for pursuing the region's most economical resource, conservation. The WPPSS fiasco is already impairing conservation financing. In its fiscal year 1984 budget, BPA counted on $58 million of external financing for conservation—funds raised by issues of tax-exempt bonds by BPA's public utility customers and repaid by BPA revenues. Now, thanks to WPPSS, the region's utilities are unable to sell these bonds.

At latest report, the OMB has refused BPA's request to increase its use of Treasury borrowing authority to cover this conservation financing deficit. Consequently, BPA cannot assure that it will be able to undertake 86 of the 96 conservation activities included in the Council's 2-year action plan adopted earlier this year.

BPA plans to implement the surviving conservation programs through contracts with the region's utilities. As of last week, 61 utilities had signed up, but these utilities account for only 30 percent of BPA's total utility load and only 15 percent of the region's total utility load. The investor-owned utilities and large public utilities are not signing, mainly due to the conservation charge they would have to pay under the contract. This charge would apply not to the power they purchase from BPA but to the power they produce for themselves.

BPA's conservation manager, who will appear before the subcommittee today, has stated that, if the large utilities do not join the program, then there is "no future for regional power planning under the least-cost mandates of the Northwest Power Act." Today we will review this apparent impasse.

Finally, even for those utilities joining up, BPA refuses to include in its program the full weatherization of any houses built slab on grade, with basements, with unventilated crawl spaces, with wood stoves, with unvented gas appliances, with private well water, or with nonpermanent electric heating systems, due to potential problems with indoor air quality in "tighter" houses. BPA for this reason also excludes all apartments from receiving the full weatherization treatment.

We will examine whether BPA has adequately considered more creative alternatives to the indoor air quality problem than simply excluding 70 percent of the region's electrically heated residences from full weatherization.

The Council's plan and BPA's implementation of it may also affect the Northwest natural gas utilities by possibly encouraging greater use of electric space heating and water heating, even though gas is a more efficient fuel for those purposes. The gas utilities are also affected by BPA's new end-user alternate fuel rate of 7 mills per kilowatthour for industrial boilers that can switch from gas or other fuels to electricity. Starting next week, BPA can offer this low rate to encourage Northwest industrial users to install otherwise uneconomic electric boilers, even before selling this energy to California at the higher 11 mills per kilowatthour rate.

We are going to take our first witness, Mr. Daniel Lamke from the Federal Energy Regulatory Commission, the time yesterday being too short to bring him before.

But first, I believe there is a vote in the House, and I will be back in 5 minutes. The subcommittee committee will recess for that period of time.

AFTER RECESS

Mr. WEAVER. Our first witness is Mr. Dan Lamke, Federal Energy Regulatory Commission.

We are pleased to have you here. Do you have an opening statement?

Mr. LAMKE. Yes, Mr. Chairman.

Mr. WEAVER. I am going to ask all witnesses to keep their opening statements to 5 minutes and, without objection, all full written statements will be placed in the record. I see it is not long, so keep it within 5 minutes.

Won't you proceed?

[Prepared statement of Daniel C. Lamke may be found in the appendix.]

STATEMENT OF HON. DANIEL C. LAMKE, OFFICE OF GENERAL COUNSEL, FEDERAL ENERGY REGULATORY COMMISSION

Mr. **Lamke**. Thank you, Mr. Chairman.

My name is Dan C. Lamke. I am a special assistant for the Acting General Counsel, Federal Energy Regulatory Commission, and I just have a few brief comments in an attempt to update my prior testimony.

First of all, as the subcommittee is aware, the Federal Energy Regulatory Commission issued an order with regard to Bonneville's rate filing. They issued that order on October 26, 1983. In pertinent part that order approved on an interim basis Bonneville Power rates for 1984-85, but rejected its transmission filing as not being in compliance with a prior Commission order directing Bonneville to meet statutory standards.

In addition, at the same time, the Commission authorized the release of a staff document entitled "Ability of Federal Energy Regulation Commission To Carry Out Its Statutory and Delegated Responsibilities for Review of Federal Power Marketing Rates Under the Current Legislative Structure."

This particular document attempts to document some of the problems that the Commission has run into in trying to administer regulatory review of Federal power marketing rates.

In addition, one of the questions directed to the Federal Regulatory Commission was on the status of the Federal repayment of Bonneville Power Administration. I can't give you specific figures at this time. The Commission in a prior order indicated that were Bonneville to have used a compound interest amortization method, as of fiscal year 1981, they would have failed to pay some $780 million. That figure would be increased to $1.4 billion if we were to use a straight line amortization method.

Assuming that the compound amortization method would be an appropriate method—starting with the $780 million at the close of fiscal year 1981—as I read their current 1983 filing and also from the comments of BPA Administrator Johnson from yesterday, this new filing purports to collect some additional $236 million in interest deferral.

In addition to that, Mr. Johnson testified yesterday that they had failed to pay the Federal Treasury amounts for fiscal years 1982-83. Those dollars would also have to be added to the $780 million.

I believe Mr. Johnson testified that in the new rate filing some $454 million are scheduled to be paid through these new rates to pick up the $236 million-plus the unpaid amounts in 1982-83, and perhaps a portion of repayment of the Federal investment to current level. So at least a significant portion of the $454 million scheduled in this particular rate filing I assume would have to be added to the $780 million to get to a current figure as to what the unpaid Federal investment would be at this particular moment.

Now, with regard to the question that the subcommittee sent to the Commission with regard to what the proper role for review is, you will note in the filed testimony that I state pretty much the fact, saying the proper role at the particular time, at least that role that is set forth in the Pacific Northwest Electric Power Planning and Conservation Act, basically is a rather limited review. The Commission is charged with making three specific findings in its review:

First, that the rates are sufficient to assure the repayment of Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administration's and other costs.

Second, that the rates are based upon the Administration's total system costs.

And third, insofar as transmission rates are concerned, that the rates equitably allocate the cost of the Federal transmission system between the Federal and nonfederal power utilizing such system.

As I previously mentioned, the document that the Commission authorized to be issued on October 26 documents a number of problems that we have had in administering this particular program. In spite of those facts, the Commission does not feel that additional authority is needed in the review, because the authority is already in the law if it were exercised and the rate establishment filed.

We are a review agency, and we are not the Bonneville Power Administration. With respect to the Department of Energy and perhaps even Treasury, if they would exercise to the fullest degree the authorities that they already have, it would greatly enhance our ability to review these rates.

Thank you. That is the end of my statement.

Mr. Weaver. Thank you.

Mr. Lamke, is it a function of the Federal Energy Regulatory Commission to require Bonneville to repay its Federal debt?

Mr. Lamke. Yes, sir.

Mr. Weaver. To see the rates are sufficient to do so?

Mr. Lamke. Yes, sir.

Mr. Weaver. How can you do that?

Mr. Lamke. We, unfortunately, are not the ultimate authority. The standard is that we approve rates that will assure repayment of the Federal investment. If those rates are insufficient to do so, our authority is ultimately one that we would reject those rates. However, in practicality that can only exacerbate the problem, which means that Bonneville could collect no rates and Treasury would collect nothing.

In that particular instance, we are rather between a rock and a hard place. Not to approve a rate that we know may be deficient would simply mean that the Federal Treasury would collect no dollars. We have no authority to modify rates. We cannot order Bonneville to increase its rates. So in the past what we have done is approve those rates on a practical type basis in the attempt to get some dollars for the Federal Treasury, with directions to Bonneville to correct its procedures.

Mr. Weaver. From your remarks, from the actions of the FERC, and from your answer now, I have to ask the question, can you effectively review BPA's rates at all?

Mr. Lamke. We can review them and come to certain conclusions. As far as correcting——

Mr. Weaver. "Effectively" is the key word in the question.

Mr. **Lamke**. That is correct.

Mr. **Weaver**. So you can't? That is really the upshot of what you have said and the actions of FERC. It is either your ineffective review, or you cannot really effectively review BPA's rates.

Mr. **Lamke**. For purposes of causing them to increase their rates, that is correct, we cannot. We can effectively review and point out as to what we consider to be defects in the rate.

Mr. **Weaver**. Is that the role of FERC, to be a teacher without even a little rule to slap wrists?

Mr. **Lamke**. Within the limitations of the authority, review authority presented to the FERC——

Mr. **Weaver**. You say——

Mr. **Lamke**. That is the result.

Mr. **Weaver**. You say in your testimony that the Treasury could also address the question of Federal cost recovery by imposing stricter controls. How could the Treasury do that?

Mr. **Lamke**. This is a particular issue that I would like to explain, and I believe that this goes primarily to what we call the highest interest first problem, that Bonneville, as well as other power marketing agencies—incidentally, what they do is, they take their highest interest first and they pay off the Treasury on that rather than amortizing payments on a levelized basis, which means that the oldest investment that a power marketing agency has, which will obviously be at a much lower interest rate, is paid last, which means the Treasury is borrowing funds at a much higher rate than what they are being repaid back for current funds.

The point there is that I think that the control of whether or not Treasury is going to collect on a levelized basis those funds should be a Treasury problem.

Mr. **Weaver**. What can they do about it?

Mr. **Lamke**. Perhaps they are the ones that can say that these loans must be paid off on a current basis.

Mr. **Weaver**. Can they order them to do that?

Mr. **Lamke**. I don't know.

Mr. **Weaver**. I see. You say that adequate authority now exists in the Department of Energy to require BPA to address the cause of its rate filing shortfalls? Do you expect the Department of Energy really to act here?

Mr. **Lamke**. They certainly have the authority to do so. They in their administrative orders—and I am referring specifically to the document called RA 6120.2, which sets out the priorities of payments on revenues for Bonneville as well as other PMAs—say that current rates should be paid rather than project interest rates, certain other filing requirements that could be required which it appears to us are not being——

Mr. **Weaver**. I see a conflict in your testimony in that you said two different things. You said everything is really all right, and you have said that you really don't have the authority effectively to monitor BPA's rates. So it would strike me that everything is not all right, and I note the remarks by Commission members, at least in the newspaper yesterday, show that they had the same feelings, calling BPA a "renegade outfit."

What is the Commission's position on Bonneville these days and is there any need to get in and get tough?

Mr. **Lamke**. Well, obviously, I think, from the statements that you have just commented about, there is certainly a high level of frustration in the Commission on the ability to be effective.

Mr. **Weaver**. What things does FERC think are needed in the Bonneville Power Administration itself or in your ability to deal with them?

Mr. **Lamke**. Well, I think to a large extent that, if the world were better structured or structured right, there are two separate functions involved in the rates. First is the rate establishment area. We feel that that is where some of the problem really exists; the people establishing the rates are not meeting fully their mandates. Were they to do so, our rate review would be greatly enhanced because basically we are a review agency.

Mr. **Weaver**. What is BPA doing wrong? That is what I want to know. I hear all the generalized remarks—"renegade." What are they doing wrong?

Mr. **Lamke**. Our problem is, first and foremost, we are probably the only person involved in this whole transaction of ratesetting that has the obligation of assuring that the Federal Treasury be repaid. That in most instances means that we are looking to increase rates, to make sure that they are being paid. Everyone else is looking to decrease rates, which puts us with a natural tension in the whole situation. Our only authority is to reject, if they don't meet that standard.

The Commission throughout this blue report, and I think in several of their other comments and testimony before Congress, has talked about the ability to modify rates.

Mr. **Weaver**. Mr. Craig?

Mr. **Craig**. Thank you, Mr. Chairman.

Just one question. There seems to be this gray area, and you seem not willing to recommend specifics as to what you feel you need to have in addition to the authority you currently have, which is basically to accept or reject but not to modify.

Why don't we remove all your authority in the area and let BPA run itself?

Mr. **Lamke**. That is one of the comments that the Commission has also made in this report.

Mr. **Craig**. Would you expand on that comment for us?

Mr. **Lamke**. Well, first of all——

Mr. **Craig**. I haven't read your blue report.

Mr. **Lamke**. Basically the conclusion is, in the absence of adequate standards guiding the policies and practices of agencies with responsibility for rate establishment, rate review by FERC cannot be fully effective. In light of these circumstances, the Commission in 1983 echoes the sentiment propounded by FPC in 1973 and recommends that the FERC either be relieved from any responsibilities in connection with rates charged or that its control over rates be made adequate, effective, and complete, if, in the opinion of Congress, it should be charged with this responsibility.

Mr. **Craig**. Then the debate is if it should be or if it should not be. It appears that if it should be you are not willing to make specific recommendations as to how it should be. I guess my conclusion then would be that maybe it shouldn't be.

Mr. Lamke. Well, obviously, as a Federal regulatory agency we will do anything the Congress directs us to do. It is very difficult, or at least the Commission has been unwilling at this particular time, to try to delineate those things that should be done, because it is a very delicate balance that we feel, because in the rate establishment field there are certin power planning functions and certain flexibilities in hydro systems that necesssarily must be handled on a day-to-day basis.

It is very difficult for us to say that we have all the answers at this particular time and should have all of the authority, because we could tip that fine balance way out of kilter and merely create more problems.

Again, I say we are a review agency and we are competent in review. I don't think that we want to get involved in the operational aspect or complete day-to-day control of any utility, whether it be a Federal power marketing agency or an investor-owned utility.

Mr. Craig. Thank you.

Mr. Weaver. Mr. Lamke, thank you very much. We appreciate your coming.

Mr. Weaver. The Chair will call Walter Pollock, Assistant Power Manager, Bonneville Power Administration.

Before you begin, I would like to show the people a chart in the Bonneville report on WPPSS 3, the Bonneville report apparently just released yesterday on what to do with WPPSS 3.

If we begin work on WPPSS 3 on a fast construction schedule, almost immediately they say we save $98 million; slow schedule, we save $114 million. In other words, it is better to go slow on WPPSS 3 if we start it now. Over here, however, it shows that if we have a July 1985 restart, a fast restart has zero savings but a slow construction July 1985 restart is the largest savings of all, $201 million.

So, in other words, Bonneville has clearly shown that WPPSS 3 should not be built now, and this is the same recommendation we understand the Northwest Power Planning Council is likely to make—that a slow construction schedule would be the best, once WPPSS 3 starts.

So, I would simply say WPPSS 3 is dead. WPPSS 3 is dead, and we understand that there have been resurrections, but it would take a miracle to resurrect WPPSS 3, and, as I say, that has occurred very seldom in the past, and I doubt it will occur again. Now with that I will let you go ahead with your opening statement before we question you.

STATEMENT OF WALTER POLLOCK, ASSISTANT POWER MANAGER, BONNEVILLE POWER ADMINISTRATION

Mr. Pollock. Mr. Chairman, for the record, my name is Walt Pollock. I am BPA Assistant Power Manager. I don't have a formal opening statement. I would, however, like to summarize very briefly the analysis we have recently conducted on WPPSS 3 and both how we did it and what we concluded.

There are, as you know, several other studies that I would also commend for the subcommittee's investigation—the Regional Council staff study, which is out now and I understand you have a copy.

There is also a study by Applied Economics Associates that is several months old, done under Washington law, under Initiative 394, which I think is comprehensive and thorough in an instructive way. There is also a study not yet completed in final form by Jim Lazar, which I think is worth your review.

Let me summarize very quickly for you the way we have done our analysis, because it is a complex bit of analysis considering the wide variety of factors.

We utilize our load forecasts as a basic building block of the analysis. As you know, we have a range of load forecasts with assigned probabilities, including a base case and both a high and low bound. That is a basic building block of our analysis.

Another important building block is the knowledge we have currently of existing regional resources, how they will perform, and what they will produce.

Third, regarding the value of surplus power during surplus periods and, equally important, during periods where additional resources may be needed under one scenario or another, what are the alternatives? How much do they cost? How available are they? When do you have to start to get them on line?

There are also costs, if you run short, curtailment costs, short-term purchase power costs, a variety of different factors. If you extend the construction of a plant, like WPPSS 3, you escalate capital costs, you do move the period of the plant availability into a period where its power is more valuable and more needed. What you trade off is escalation and plant costs. So that is an important tradeoff.

To further complicate the matter, we are not like other parts of the country. We have a majority of our electrical system performance dictated by the vagaries of nature—that is, how much water comes each year, when do you get it? On a statistical basis, that must be considered. All of those factors and a variety of others go into our analysis.

Let me just summarize the principal findings we have had at this point in time, and I am sure as we discuss this matter we will have a chance to explore some of the specifics that are the most important variables that drive this kind of analysis.

As the chairman pointed out, under base case assumptions, a gradual restart of construction of WPPSS 3 in about 1985 is somewhat less costly than early restart. However, changes in certain assumptions, certain underling assumptions in this study, can alter that result. In particular, depending on the precise construction management plan the Supply System employs, the result could be tilted somewhat in the direction of an earlier restart.

Our conclusion, based on examination of those variables and sensitivity of those analyses to such considerations, is that on an economic basis there is not a compelling argument at this point in time for either early restart or a reasonable period of delay. That is, the economics look approximately equivalent for scenarios within the range of early restart to a 3½- or 3-year delay of the project.

The best current load resource information that we have based on our load forecasts, and also looking at the Council's forecast, are that we in the region can tolerate a 3- to 4-year delay in the project. The region has sufficient resources not to be in deficit in that period with the 3- to 4-year delay. We might be able to tolerate it longer. If we get a low load growth, that period extends considerably. If we get a high load growth, it shortens. But under base assumption, the most likely assumption is we can tolerate a 3- to 4-year delay.

The analysis that we have performed continues to show that loss of WPPSS 3 to the region would be a very costly occurrence, that in our mind the issue is the construction schedule for WPPSS 3, not the need for the project.

The loss of that project by our analysis would expose the region to somewhere between $500 million and $1 billion of additional incremental costs. So there is a badly needed project. The issue in our mind is schedule.

The course of action with the most adverse impact--this is an interesting result--is immediate fast construction followed by sometime in the future termination for one reason or another.

Now, termination is a very sensitive issue in a lot of quarters. The investigation we have conducted shows that typically in this country nuclear plants have been terminated, when they have been concluded to not be needed, not because of interventions or because of license actions. Really, the need is the primary variable that drives the ultimate construction of the plants.

If you look at nationwide experience, it is possible that that could occur. It is not likely. If that occurred, we would have to slow down all other resources in the region and reinvest that also. That is why we get this result, that the most adverse course of action is early restart, eventually finding you have very low loads and then terminating the resource at that point in time.

Under our low load forecasts, it is a fact that this resource would have to be closely examined. It might not be needed to serve regional needs.

We have examined the issue of surplus power exports, and our conclusion there is that with WPPSS 3 the considerations are not decisive in issues of firm power exports. That is, there is a relatively small benefit to accelerating a plant to supporting a firm export sale. That is because there are other resources that could also be accelerated.

So, I would summarize that issue by saying that is not a decisive determinant. There is not a direct and immediate and imperative relationship between those issues. In its own right a surplus sale might be a good idea for the region for other reasons. That needs examination.

Mr. Chairman, there are a great many other variables that we have examined and I know that you and your staff have not had time to go through our analysis in detail. We ran 41 separate analyses of this matter to consider its sensitivity to what we thought were the key variables--the kind of financing, the role of other resources. We ran scenarios where we doubled the amount of conservation available in the region to see what difference that made.

We made different assumptions about some controversial issues, about treatment of interest rates, AFUDC, and other issues that there are a wide variety of opinions on. We looked at marketing carefully.

As you examine this report, we have tried to anticipate the most likely questions that readers will have and run specific comparisons to address those matters.

In conclusion, our summary report finds that the project is needed, there is a major impact on the region if it is lost. The issue of schedule is one that is not driven decisively by resource economics, as long as the plant is constructed within a reasonable period of time. By reasonable I mean a delay of not more than about 3 to 4 years.

Thank you.

Mr. **Weaver**. Thank you, Mr. Pollock.

That was very fine testimony. You say that WPPSS 3 is badly needed. I quote you, "badly," in the future, right?

Mr. **Pollock**. Yes.

Mr. **Weaver**. But under your scenario, as to when it is needed and how much it would cost, it is clear that we would be better off never to have started. In other words, if you say, agreeing with you—I don't—agreeing with you that it is badly needed in the future, we would be better off to start it in the future as opposed to having started it already; is that not correct?

Mr. **Pollock**. I think if we had perfect knowledge in 1972 or 1969, whenever the plans were laid, we would have known load growth of 2 percent and not 6 percent, we would not have started the project then.

Mr. **Weaver**. I am simply saying that, given your data, your analysis——

Mr. **Pollock**. Yes, sir.

Mr. **Weaver**. Given that assumption, we would be better having started it later than now?

Mr. **Pollock**. We would have been better starting it later than the early 1970's, Mr. Chairman. I can't specifically answer your question as to when you would have started it. In hindsight this matter is difficult. So our analysis has been based on starting where we are right now.

Mr. **Weaver**. I am not talking about hindsight. That is not the question I am asking. I am asking with your data.

Mr. **Pollock**. Yes, sir.

Mr. **Weaver**. That it would be better in 3 years, with a slow start, a slow construction, that we would simply under your data be better off if we had, assuming your assumption that we badly needed it, we would be better off having started in 1985, 1986.

Mr. **Pollock**. Oh, I understand your question. I would not state it quite as decisively as you have. I would state it that we can wait 2 to 3 years and it will not impose an economic penalty. The reason I am not stating it as strong is that you can vary some key assumptions and get a different result in that regard, or a slightly different result.

Mr. **Weaver**. Let's talk about those assumptions.

You said under a low forecast, the plant would not be needed at all.

Mr. **Pollock**. That is right.

Mr. **Weaver**. What is that low forecast?

Mr. **Pollock**. That low forecast is about a little bit more than 1 percent compounded annual growth per year.

Mr. **Weaver**. 1.3 percent?

Mr. **Pollock**. That is right, and that is assuming that all other resources perform as scheduled and at the cost that we have estimated. So there are a lot of underlying assumptions in the analysis.

Mr. **Weaver**. So there is a scenario that WPPSS 3 would not be needed at all?

Mr. **Pollock**. There is a scenario.

Mr. **Weaver**. 1.3 percent load growth.

The recent forecast is 1.8 percent, is it not?

Mr. **Pollock**. That is correct, and our estimate of the likelihood of the 1.3 percent load growth is less than 10 percent.

Mr. **Weaver**. I am taking bets that we have a negative load growth in the next 10 years. We will see.

Mr. **Pollock**. I won't dispute there are a lot of opinions on that matter. We have done the best job we can of load forecasting using the best data available, and you know what our range is but certainly other opinions in the matter—

Mr. **Weaver**. If OPEC suddenly cut off all the oil, we do not rely but very little on oil generation in the Northwest, what effect would that have on Northwest power demands if suddenly, for some reason oil prices skyrocketed for a sustained period of time? Would that have a strong effect on Northwest energy needs or prices?

Mr. **Pollock**. I think it would, Mr. Chairman.

Mr. **Weaver**. Tell us about that.

Mr. **Pollock**. There are a number of things that would happen in terms of the direct dependence in the Northwest on OPEC oil. It is not strong. But I think the consequences would indirectly drive up the price of other fossil fuels, coal, and domestic oil.

There is some dependence on those fuels in the Northwest for power generation. It would basically drive up the price of electric power, I think, and would make all available sources of electricity, including nuclear, more competitive.

Mr. **Weaver**. How about demand, it wouldn't have an effect on demand in the Northwest?

Mr. **Pollock**. I think it would have an effect on demand.

Mr. **Weaver**. Tell us why.

Mr. **Pollock**. For the very reason I stated, that it would drive up energy prices and it would further dampen demand. I think we have seen evidence of that——

Mr. **Weaver**. It would dampen demand?

Mr. **Pollock**. Yes.

Mr. **Weaver**. We would actually through higher oil prices use less energy in the Northwest?

Mr. **Pollock**. That is my——

Mr. **Weaver**. Including electricity?

Mr. **Pollock**. It would be hard to know how the balance of fuel use would change. Overall, I think we would use less energy in the Northwest. My judgment is that it would probably drive up the use of electricity potentially.

Mr. **Weaver**. Did Mr. Katz have some wisdom?

Mr. **Pollock**. My consulting economist had a view that I think is important to give you about elasticity between the competing fuels.

If oil goes up, and electricity doesn't go up as much, it tends to shift use toward electricity. That would be offset by the rising price of all fuels. It is really a very difficult question to answer.

Mr. Weaver. Has Bonneville done any studies in this regard?

Mr. Pollock. We have, but not on an oil embargo. We do have price elasticity of fuel in our forecasting models, but we do not predict and incorporate the results of a stoppage of foreign oil.

Mr. Weaver. The scenario, at least the conventional wisdom, is that oil prices will remain soft for many years, OPEC is now on half production, and a flareup, an Iraq-Iran flareup would raise energy prices very sharply but only for a temporary time and so, therefore, the likelihood is as of now that until perhaps the year 2000, when oil reserves start really seriously dwindling, that we are not in that kind of situation.

The gentleman from Idaho.

Mr. Craig. Thank you very much, Mr. Chairman.

Mr. Pollock, I appreciate your testimony and the succinctness with which you gave it.

Let me ask a couple of questions as it relates to WPPSS 3 and some of the cost factors you are talking about toward rather early startup versus a delayed startup and the models that you have projected as to if, what, why, or if, what, how.

You are talking about a load growth, the load growth variables assuming everything within the system is working pretty well.

In that 1.3-percent growth factor, and you say assuming everything works well, where does Mother Nature come in? In other words, how have you been able to project in the variables a low water year or series of low water years and what kind of impact that has on the system and the potential revenue of the system as it relates to financial obligation?

Mr. Pollock. Congressman Craig, what we have done is perform a load-resource study under critical water conditions. That is the lowest conditions, basically the lowest conditions of record, and our load reorganization planning is done on that basis. When we do the resource analysis as described in this result, we actually model the random occurrence of various water years in succession and conclude for each of those years how much cost the region would incur, how many loads wouldn't be served, what would have to be curtailed.

We do have enough of those analyses on a statistical basis that we can basically average them together to conclude an economic result. We have not extracted from this study the question of how often do our revenues underrun or overrun. We have a capability to do that, but the focus has been more on the economics of these resources.

Mr. Craig. Let's say that within the next 5 years or 6 or 7 years, based on a slow start on WPPSS 3, during that period of time, what is the likelihood, based on historical evidence, that you will experience at least one or more low water years?

Mr. Pollock. I would say probably 5 percent or less.

Mr. Craig. 5 percent or less?

Mr. Pollock. Yes, sir.

Mr. CRAIG. So then, in other words, we are saying that a low water year is not really a concern at this point in the overall load demand on the system without WPPSS 3? Are you saying that?

Mr. POLLOCK. No, Congressman, actually in those studies, those are some of the few studies that we perform where we do come up short in some years. You get load growth, you don't have WPPSS 3, and you come up short. That actually does happen. The way we have modeled it is, we model short-term purchases to make up for those deficit periods. We model that at a fairly high price. That is an uncertainty in our modeling.

We may not have modeled that high enough price; we model at 60 mills a kilowatthour whenever we come up short. If that price were wrong, then our conclusion might be wrong about the need for WPPSS 3 under a low load growth scenario. That is one of the key variables in that analysis.

Mr. CRAIG. In your current rate requests, that is $2 billion plus in 1984, and with staff studies of the Council appearing to say that an early start-up of WPPSS 3 would represent *x* billions of dollars to the system in total system cost versus delay representing *x* billion dollars. We find that a delay appears to be a net savings of around $352 to $360 million on a delay start of WPPSS 3.

How much of a change in the normalcy of operation of the system, how much of a change in water, how much of a change in demand, would represent to you a net loss based on your current rate projections of $350 million that would not be lost if WPPSS 3 were in place and in operation? Have you done that kind of study?

Mr. POLLOCK. We haven't done precisely that study, but I think I could give a sense of those proportions.

First of all, by way of clarification, I would not say that we save $300 million by delaying WPPSS 3 for 3 years. I would say, based on this analysis, we may not save anything.

Mr. CRAIG. It is a wash?

Mr. POLLOCK. It may be a wash and we need——

Mr. CRAIG. At least what I am referring to is under one set of scenarios.

Mr. POLLOCK. That is right.

Mr. CRAIG. A scenario it appears that there could be a savings of $300 to $360 million?

Mr. POLLOCK. That is right.

To answer your question, Congressman, this last operating year we experienced somewhat on that order of magnitude an impact in our revenue recovery, $300 million, on that order. That is not precisely less than we expected. That was driven really by three events: A recession, a warm winter, and very peculiar circumstance that, as discussed yesterday, abundant rainfall, so I think it is entirely possible in any given year that our revenues could swing $300 million because of those kinds of vagaries up or down. We have a case in point.

Mr. CRAIG. If WPPSS 3 had been on line in fiscal year 1983, was there a market for the power it would have produced, that would have made up the difference of the $360 million? Could you have marketed power at that?

Mr. POLLOCK. We could not have had the entire $360 million, no, Congressman.

Mr. Craig. So what you are saying is, though, based on a low of 1.3 percent in growth or demand—and what is your high projection, your high side——

Mr. Pollock. About 2.4 percent.

Mr. Craig. Within that scenario, you are saying that at some time in the near future WPPSS 3 will be needed?

Mr. Pollock. Yes, sir. And it is important to look at each of those load growth scenarios. And in summary, what our analysis shows is only under a low load growth scenario is there are potential economic advantages associated with not having WPPSS 3. Under all other growth scenarios WPPSS 3 is needed and its loss would impose substantial costs.

If you weigh the probability of those scenarios, which we have done, we performed that analysis, the net cost taking all those different probabilities into account, is $500 million-plus, if we did not have any WPPSS 3. When you have a chance to study the Council staff report, I think you will find the same conclusion there.

Their net cost, weighing all the probabilities of events, load forecast and all the other events they have studied, is about $500 million, also.

Mr. Craig. How many scenarios? How many load growth scenarios have you made to date?

Mr. Pollock. We have run 41 separate studies combining load growth and other events.

Mr. Craig. In 41 separate studies, how many times did you come up needing WPPSS 3 versus how many times did you come up in not needing WPPSS 3? What are the odds in this case? It is a gamble at best, it appears, because we know we are dealing with a variety of variables, some out of our control.

Mr. Pollock. I am sure a statistic and——

Mr. Craig. You guys have been accused of being blackjack dealers and renegades; what are the odds? Let me get with it here.

Mr. Pollock. I think the odds are, based on all analyses we have done, the odds are 95 percent or better that we need WPPSS 3 and would suffer substantial increased costs if we didn't have it. We ran 41 scenarios. In only one or two of those cases was WPPSS 3 not cost effective overall. There are a lot of questions about the precise schedule, but that would be my order of magnitude estimate.

Mr. Weaver. Would you yield?

If the gentleman wants to give me 9-to-1 odds, I will take it.

[Discussion off the record.]

Mr. Craig. Thank you, Mr. Pollock, for your statement and your responses. I think it is very easy for this body or any individual here to pick out that which he or she might prefer, it sounds good for at least what they want to say. It appears, though, based on the best information available, given all the variables, odds are that down the road a way we are going to need some more power.

Would you assume that is true?

Mr. Pollock. Yes; I agree with that.

Mr. Craig. Thank you.

Mr. Weaver. Mr. Pollock, what dollar, actual dollar figure did you use for the cost of WPPSS 3?

Mr. **Pollock**. Mr. Chairman, we used different dollar figures depending on the construction timetable. I could tell you roughly what those——

Mr. **Weaver**. Give the one with the 1985 slow construction.

Mr. **Pollock**. The 1985 slow construction was about $1.4 billion to go in 1983 dollars.

Mr. **Weaver**. For whom?

Mr. **Pollock**. For all shares, Bonneville and the developer owned.

Mr. **Weaver**. Total construction?

Mr. **Pollock**. Yes; cash flow in 1983 dollars. Those numbers are reported in some detail in the report, and I know you haven't had a chance to go through it.

Mr. **Weaver**. $1.4 billion?

Mr. **Pollock**. Yes, sir.

Mr. **Weaver**. That doesn't include interest on the existing money?

Mr. **Pollock**. No; it does not.

Mr. **Weaver**. Does it include interest on the money during the future construction?

We will get answers to these technical questions from you later. Our estimate is that it is going to cost $2 billion if you continue construction now, so I am kind of wondering about this figure.

Mr. **Pollock**. I think, Mr. Chairman, that our number does not include AFUDC for an investor-owned utility.

Mr. **Weaver**. That is what I wanted to know; it does not include that. So we are up to close to $2 billion with that. Right?

Mr. **Pollock**. It is difficult to add all of the interest, AFUDC numbers, add one to another. The present value in 1983 dollars of the cost to go on the project is about $1.4 billion, we would estimate.

Mr. **Weaver**. Including the private utility share?

Mr. **Pollock**. Yes, sir.

Mr. **Weaver**. That is the figure you are using?

Mr. **Pollock**. Yes.

Mr. **Weaver**. Well then, I would say that it is going to cost lots and lots more money than that, given everything we know about it.

My second question deals with the fact that there are two methods of analyzing costs of these plants. One is called life cycle cost, one is called perpetual replacement. Which did Bonneville use in its analysis?

Mr. **Pollock**. We used the perpetual replacement method which takes into account the eventual replacement of the resource at the end of its life.

Mr. **Weaver**. Exactly.

Are you familiar with the Northwest Power Planning Council analysis?

Mr. **Pollock**. Yes; I am.

Mr. **Weaver**. They used both life cycle and perpetual replacement, did they not?

Mr. **Pollock**. They did.

Mr. **Weaver**. And I just want to make the point, and have it confirmed by you, that perpetual replacement that you used and we think is by far the more credible analysis, shows WPPSS 3 to be far, far less needed, or at least the cost of it higher in terms of when and if it is started, than does life cycle cost analysis.

Mr. **Pollock**. Life cycle analysis does give you results that favor earlier restart of construction, at least the way the Council has done it. We did not perform that analysis.

Mr. **Weaver**. You agree, obviously, that perpetual replacement is better?

Mr. **Pollock**. I think it is more comprehensive, Mr. Chairman. There are some problems in doing that kind of analysis in speculating what is going to replace the resource and what it will cost.

Mr. **Weaver**. My point is that the press releases that the Power Council is putting out are based on life cycle costs, and so they have consciously and deliberately used the method that will bring in lower costs to put out to the public, while they used both methods. You say the perpetual replacement is the better one, so they are deliberately putting out the more favorable method in stating their position on WPPSS 3.

Mr. **Pollock**. Mr. Chairman, I haven't seen press releases or other material. Their report itself I think does do a good job of showing the difference between the analyses and the difference between the results.

Mr. **Weaver**. Yes; it does.

They are putting out press using only the one, which shows you where the bias is. The Power Council should not have any bias. That is just very disturbing to me, very disturbing. We got one more entity, and I am saddened, but it is promoting something when they are not supposed to be.

Does the gentleman from Arizona have any questions?

Mr. **McNulty**. I do not.

Mr. **Weaver**. How does your study account for risk that, even after restart of construction, WPPSS 3 will never be completed or, if completed, never operate?

Mr. **Pollock**. Mr. Chairman, we take that into account by running the low load growth case, because the study we have done of experience with nuclear plants in the country tells us that the reason that occurs is because the plan isn't needed. So that is the way we have explicitly taken that variable into account.

Mr. **Weaver**. How much did you crank into your supply side in terms of supply in the Northwest of geothermal?

Mr. **Pollock**. We don't have a lot of geothermal. The primary economic resources that are the competition, if you want to view it that way, are conservation, hydroelectric, cogeneration and coal, roughly in that order. We have not concluded that geothermal electricity is competitive at this point.

Now I am not saying that geothermal direct use isn't immediately competitive.

Mr. **Weaver**. How have you concluded that, when you have never done anything about it?

Mr. **Pollock**. There are no proven economic geothermal generating resources in the Northwest right now. There are some promising ones, and we are putting out a solicitation to see if someone can produce geothermal electricity at 10 percent more than the price of coal-fired generation. If the answer comes back that they can, we might well change our estimates.

Mr. WEAVER. There are very, very successful geothermal just a few miles below the Oregon border, are there not?

Mr. POLLOCK. Yes, sir; the Geysers is an economic——

Mr. WEAVER. Very profitable, are they not?

Mr. POLLOCK. I think they probably are, to the owners.

Mr. CRAIG. Would you yield?

Mr. WEAVER. Surely.

Mr. CRAIG. This whole issue of geothermal was of great popular concern 10 years ago, and my State was one of those you have had in the Northwest as a potential for real productivity in the area. That potential on a graph has dropped dramatically, based on a variety of testing that has gone on in my State during that decade, some very thorough testing on the part of private entities in which they have come in and done a tremendous amount of leasing of ground and have drilled a variety of test holes in areas to find that water. And it isn't found, or it isn't found at least at the level necessary in either volume and/or heat, and I think that in large part for you to not consider it based on the decade's experience is a reasonable approach.

Mr. WEAVER. May I reclaim my time?

Bonneville is under $6 billion in debt for nuclear plants, which by the way haven't produced a single kilowatt of electricity. $6 billion.

How much money prior to this year have you spent developing geothermal? How much money have you spent at all developing geothermal? The answer is zero.

Mr. POLLOCK. It is not zero. We have spent money on geothermal. We have a contract right now with——

Mr. WEAVER. Before 1983, how much did you spend developing, drilling wells, I am talking about?

Mr. POLLOCK. We have not spent money drilling wells.

Mr. WEAVER. Not a penny, have you? For nuclear, $6 billion. I had a hearing 9 years ago, in this subcommittee, or its comparable one, in which the best experts in the Northwest said sitting in the Cascades was more energy from geothermal than Saudi Arabia had oil, so from that point on Bonneville spent $6 billion on nonproducing nuclear plants and none on developing that geothermal resource.

And I think we had better go vote now.

Mr. CRAIG. Mr. Chairman.

Mr. POLLOCK. I would like to respond.

Mr. CRAIG. I suggest I am also pleased that BPA has not put out a lot of money into harvesting moonbeams either.

Mr. WEAVER. I don't know about moonbeams.

Mr. CRAIG. You should.

Mr. WEAVER. I will make you the moonbeam expert. Northern California, very close to my congressional district, has some. What is it, 1,500 to 2,000 megawatts now of geothermal?

We will recess for a few minutes to vote.

AFTER RECESS

Mr. WEAVER. The reason I am dwelling on geothermal, Mr. Pollock, and I would want very briefly to ask you about solar and other forms, is that these have enormous potential for producing power in the Northwest. But you have not used them in determining whether WPPSS 3 is needed or not. How much have you given for solar generation?

Mr. Pollock. Mr. Chairman, there is some solar I believe incorporated in our conservation supply. I can't tell you precisely.

Mr. Weaver. Passive solar, right?

Mr. Pollock. Yes, sir; I believe that is——

Mr. Weaver. But in your analysis, you did not use any factor for geothermal electrical generation or solar electrical generation, did you?

Mr. Pollock. That is right. I would like to provide a little bit more information on geothermal, because we have considered that quite carefully. I want to correct something I said before you left.

The offer we are about to make for geothermal electric demonstration projects is to pay 50 percent more than the cost of coal generation, not 10 percent more. In the past we have looked carefully at geothermal, and there has been a lot of Department of Energy money spent in the Northwest, not Bonneville money. Quite a few holes have been drilled by the Department of Energy with their funds at Mount Hood, Old Maid Flats, Timberline Lodge, and a demonstration project in eastern Oregon, as well as the Raft River geothermal project in Idaho.

The basic difficulty in the Northwest with geothermal electricity is the source isn't quite hot enough. We felt up to this point that new technology would be required. There are some promising new technologies. We are hopeful that this demonstration approach will——

Mr. Weaver. Mr. Pollock, do you think that they have spent 1/1,000 as much on geothermal as they have spent on nuclear?

Mr. Pollock. My guess would be, Mr. Chairman, they have probably spent $50 million in the Northwest on geothermal.

Mr. Weaver. Including Raft River. In the Cascades no hole has been drilled deeper than 3,000 feet, and only 1 of those that——

Mr. Pollock. Old Maid Flats, I think, was deeper than 3,000 feet, but I might be wrong on that.

Mr. Weaver. I don't want to belabor.

My point is you have not factored this into the WPPSS 3 study. I just simply am trying to take your testimony and what you have come up with and put some real serious doubts into the assumptions in it. That is all I am trying to do.

Mr. Pollock. We have considered those and concluded they are not competitive——

Mr. Weaver. I know you have. Obviously you did, by spending $6 billion on nuclear and zero on geothermal. You made that conclusion very clear.

I don't think it could be clearer.

Are there questions by either of the gentlemen?

Mr. McNulty. No, thank you.

Mr. Weaver. Because I have other questions here, and I wanted to go through them.

Mr. McNulty. Mr. Chairman?

Mr. Weaver. The gentleman from Arizona.

Mr. McNulty. Mr. Pollock, I have not been here, and I apologize to you. The only inquiry I have is, based on a quick review of these things, they indicate there is a plan to resume and perhaps complete construction on three of the nuclear plants. Is that so?

Mr. Pollock. That is correct.

Mr. McNulty. And you are testifying here today in behalf of that course of conduct?

Mr. Pollock. Yes, I am reviewing the results of the studies we have done with respect to if that is economic to do, and when it is economic to do.

Mr. McNulty. Well, and you have testified in effect that it is and that that will be done at some future date, I gather.

Mr. Pollock. That is correct.

Mr. McNulty. Would it be fair to characterize this course of conduct as the least worst option?

Mr. Pollock. Congressman, I would charge it as least cost option in the sense that all of these things cost more, have some impact on rates that is a bad result. But it is the least cost option.

Mr. McNulty. And you would not care to characterize it as least worst option?

Mr. Pollock. If you mean that the other courses are even worse?

Mr. McNulty. Yes; I do.

Mr. Pollock. That is what I am conveying.

Mr. McNulty. Thank you.

Mr. Weaver. Mr. Pollock, do you include as a cost of completing WPPSS 3 the $269 million in shared costs contributed to the project by the participants of WPPSS 5?

Mr. Pollock. No; we do not.

Mr. Chairman, I want to be sure I understand your question. I think, if I understand it correctly, you are asking whether we have included costs that may be assigned to the project due to a cost-sharing settlement of litigation that is in progress. The answer is, I know we have not included those costs.

Mr. Weaver. That is a liability, is it not?

Mr. Pollock. It is a possible liability, but it would exist whether or not the project were completed.

Mr. Weaver. Why would it be imposed if the plant were not complete? What legal entitlement would be there if WPPSS 3 were not completed? I can see none.

Mr. Pollock. The issue there is the costs that have been incurred and which of them should be assigned to the net-billing WPPSS 3. I am sure that the litigants in that litigation would argue that those costs have been incurred and ought to be assigned to the owner of WPPSS 3 regardless of its construction status. We are obviously arguing those costs are not legitimate to assign to WPPSS 3. Whether we will prevail or not in the litigation I don't know.

Mr. Weaver. Do you include as a cost of completing WPPSS 3 the probable need for midlife steam generator replacement?

Mr. Pollock. We do not explicitly include that. We do escalate operation and maintenance costs to include some interim capital replacement. I can't tell you whether there would be enough money in that or not for a specific replacement of steam generators. I don't know.

Mr. Weaver. Who does know?

Mr. Pollock. I would have to look at the numbers and see and look at an estimate. I am sure the Supply System could answer that.

Mr. Weaver. That could be as much as $200 million.

Mr. Pollock. It could be very costly.

Mr. Weaver. Sounds like it. I am beginning to think these things have been tripped a bit. Does WPPSS 3 have a good fuel contract?

Mr. Pollock. A good—I am sorry, Mr. Chairman—a good——

Mr. Weaver. How much money would WPPSS 3 save due to the fuel contract compared with the current marketplace for nuclear fuel?

Mr. Pollock. They do have a good fuel contract, yes, sir; in that we have based our fuel analysis on the provision of that contract.

Mr. Weaver. Couldn't you sell it then?

Mr. Pollock. I don't know.

Mr. Weaver. And raise some money?

Mr. Pollock. If you don't, then that wasn't factored in, because that would be a cost benefit of not doing the plant, so that again is not factored in.

Mr. Weaver. Does your analysis include the fact that, if WPPSS 3 is terminated, the private utilities can write off the investment?

Mr. Pollock. No, we have assumed a full sunk cost. We have not considered them in any way.

Mr. Weaver. That could amount to a tax saving of as much as $300 million. There again is another factor you have not used. Does your conclusion that WPPSS 3 is vehemently cost-effective to build in any way depend upon a long-term surplus firm power sale to California?

Mr. Pollock. No.

Mr. Weaver. You explained that, I think, in your export paragraph.

One final question. I find your analysis woefully lacking. I am not disparaging the quality of your analysis, Mr. Pollock, I am simply saying some of your assumptions showed that you didn't crank in by any means anywhere near all the things that should be cranked in. I think for California, geothermal and solar and some of the other factors could be enormous contributors in the years to come.

One final question. When you bring WPPSS 2 on line, won't it just give you more surplus power and force you to sell energy to California at a lower rate?

Mr. Pollock. It will give us more surplus power. I don't think it will force us to sell power to California at a lower rate. I know you had an extended discussion of that issue yesterday.

Mr. Weaver. I know that, if I had a lot of office space and my buyers could pick and choose, then I didn't get as good a rental rate. Apparently that doesn't apply in the electric business. The more you have to sell, the more glut there is, that doesn't affect prices?

Mr. Pollock. It does affect prices.

Mr. Weaver. It does? Why wouldn't bringing on an 1,100 megawatt plant affect prices?

Mr. Pollock. Because there are critical points at which that effect is felt. It is not a linear relationship. It is basically a matter of when the intertie is full, prices fall. When the intertie is not full, prices are relatively stable. The underlying fact is that there is a large, large oil displacement market in California that it is economic to displace at any of the prices that we sell energy to California. So, unless the intertie is full, the prices are relatively stable and relatively high.

My judgment about the availability of WPPSS 2 power is that it will not create a situation where the intertie is full most of the year. If that occurred, then I think your premise would be right. Availability of that power would force prices down. But I don't believe we will reach that break point.

Mr. Craig. Could you give us some figures on the displacement of oil or fuel generation energy in California? You said, I think, you could displace that at any of your given scenarios.

Mr. Pollock. Yes, sir; Congressman Craig, the rough estimate of the displacement market, the amount of oil, oil-fired generation in California typically can be displaced is somewhere on the order of 5,000 to 6,000 megawatts. The cost of operating the generation varies depending on the fuel contract conditions, but in general, under today's oil prices, it is somewhere in the order of 40 to 50 mills per kilowatthour. That is the cost savings when they shut down the generation.

The intertie transfer capability between the Northwest and Southwest is somewhere between 3,000 and 4,000 megawatts. That is, the pipeline is smaller than the market. So when the pipeline is not full, competition in California will hold the prices pretty high. When there is a superabundance in the Northwest and the pipeline is full, the prices go down. That is what happened this last year.

Mr. Craig. Is there a willingness or a desire on the part of California to permanently shut down those oil-fired operations if they could gain relatively firm power out of the Pacific Northwest?

Mr. Pollock. They are interested in both shutting the facilities down or in displacing capital improvements on their systems—that is, their added costly resources that could be moved out in time with a firm transaction.

Mr. Craig. You are telling us that you could supply them with that power at a cost better than that at which they can produce it?

Mr. Pollock. Yes.

Mr. Craig. Even under new facilities on their part?

Mr. Pollock. Even in the near term, even under new facilities. That is an issue I know this committee explored to some extent here in recent hearings, and it really is deserving of a lot of amplification. There is risk and benefits in both ends that have to be evaluated.

Mr. Craig. Thank you.

Mr. Weaver. Mr. Pollock, we have to go vote, and I am going to ask you one final question.

In determining whether you are selling nonfirm surplus energy to California—which you are not doing right now; you are filling the reservoirs instead—do you—I know you can't predict the future, weather and water—but do you use any long-range weather predictions in making your decisions like this? I am curious to know that.

Mr. **Pollock**. Not longer than a week.

Mr. **Weaver**. Is that right?

Mr. **Pollock**. That is right. We use weekly projections.

Mr. **Weaver**. Doesn't the U.S. Government, if you are long-range——

Mr. **Pollock**. There are projections. We have had internal debate about whether there is validity in using those right now. Our conclusion has been no.

Mr. **Weaver**. So you just go on an assumption of normal weather?

Mr. **Pollock**. That is right. We do use the statistical occurrence of weather and rainfall in predicting how the system will operate, but in planning our operations, no, we don't make long-range weather predictions.

Mr. **Weaver**. We have to vote.

Thank you, Mr. Pollock. We appreciate very much your testimony.

We will be calling Mr. Hickok next, and will be back in a few minutes from voting.

Mr. **Pollock**. Thank you, Mr. Chairman.

AFTER RECESS

Mr. **Weaver**. Steven Hickok and Richard Fiddler, please.

That will be our last interruption and I think we can progress. Thank you very much for coming. Would you proceed with any remarks you may have.

STATEMENTS OF STEVEN HICKOK, CONSERVATION MANAGER, BONNEVILLE POWER ADMINISTRATION, ACCOMPANIED BY MIKE KATZ, ASSISTANT TO THE ADMINISTRATOR AND LIAISON TO THE NORTHWEST POWER PLANNING COUNCIL

Mr. **Hickok**. Mr. Chairman, for the record, I am Steve Hickok, Assistant Administrator for Conservation, Bonneville. I am accompanied by Mike Katz, who is Assistant to the Administrator and Bonneville's liaison to the Northwest Power Planning Council.

Mike, incidentally, has probably attended more meetings of the Council than anybody. I am sure in the absence of Council witnesses today, if you would like, Mike could jump at the opportunity to speak on their behalf.

I don't have a prepared statement this morning, Mr. Chairman. You know generally the status of the conservation program of Bonneville. I have come back to Washington frequently to brief you and members of your staff.

We have, of course, offered long-term conservation contracts to all 129 of Bonneville's customers within our States. And we are proceeding into fiscal year 1984 with a budget that anticipates taking those steps in the Council's 2-year action plan that will prepare the region to proceed along that least-cost path of meeting our future electric energy demands—and that is a conservation-based strategy. It is one that we fundamentally agree with the Council on, and we are proceeding as rapidly as we can to put it into place.

[Prepared statement of Richard Fiddler, with supplementary testimony, may be found in the appendix.]

STATEMENT OF RICHARD FIDDLER, SEATTLE CITY LIGHT DEPARTMENT

Mr. Fiddler. Thank you.

My name is Richard Fiddler. I am here today on behalf of the city of Seattle and a municipally-owned utility, Seattle City Light.

We are grateful for the chance to appear today to discuss what we consider to be a very serious problem that is arising in the region concerning the long-term conservation contracts. We think it is an excellent time to get a broader discussion of these issues, and so we are grateful for the chance to appear today.

We are speaking today from the perspective of a city which has for many years worked to establish the reliability and validity of conservation as a realistic alternative resource, and it is that equivalence of cost-effective conservation and generation that lies at the heart of the city of Seattle's concerns with the Bonneville proposed contracts. And I would like to make it clear at the outset that we think that conservation can be an excellent resource for the region. We think it can be in most cases the cheapest alternative resource for a long time to come. We think that it can compete very well, and that we need to establish good sound financial relationships in order for it to do so. That is the perspective that we bring today.

Currently we have a serious impasse. The conservation contracts which have existed between Bonneville and the region's utilities to provide regional funding for conservation have expired. They expired at the end of September of this year. Bonneville has offered long-term replacement contracts, as Mr. Hickok described, but there are certain provisions in those contracts which have made it very imprudent for Seattle and many other utilities that have their own generation to sign. I will go into that in some detail later.

We think that those provisions pose a real threat to the equivalence of conservation as a resource in the region.

Finally, we believe that this disagreement that many of the utilities are having with Bonneville about conservation contracts are the result of an incomplete understanding around the region by policymakers and their staffs as to what the facts are about who benefits from conservation and what kind of institutional arrangements we have to make in order to have conservation take its place as the kind of deal that no one can or should refuse.

So we think that we are on a learning curve for conservation and that our present difficulties that we are having with Bonneville, and some other utilities are having with BPA, are part of that learning curve in the region as we come to understand these institutional arrangements better.

The seriousness of the situation right now I should underline. It seems likely that at this point the customers who amount to about 50 to 70 percent of the region's utility load may not have conservation contracts with by Bonneville. It is a very real threat to the ongoing conservation programs in the region, and one which we take very seriously.

I think our main concern here is in trying to suggest solutions and a role for the Congress to play at this point. We believe that it is not the time for a final showdown about the form or nature of conservation contracts.

We are concerned about Bonneville's haste to enshrine in a long-term contract certain institutional arrangements which they prefer but which are still the subject of intense debate around the region. And it is not only the arguable concerns about fairness and equity which you hear in rooms of this sort a great deal, I am sure, Mr. Chairman, but also the basic facts upon which those equity concerns should be based.

For an example, about the benefits of conservation and the facts, I would mention that in the 1982 Bonneville rate proceedings there was an elaborate discussion of who benefits from conservation: To what extent do Bonneville ratepayers benefit, to what extent do individual utilities benefit, and to what extent do individual retail customers benefit?

That was a very clear discussion in Bonneville's rate proceedings with which we essentially are in complete agreement. We came to the 1983 rate proceeding and found that Bonneville had revised dramatically their discussion of benefits, and that the distinction between a utility and its customers had been lost. It was not nearly as correct a discussion. And upon this new discussion the current contract charge proposal and methodology in the Bonneville rate proceeding was based.

When we have a complete change in the nature of the debate about who benefits, we believe it is the wrong time to force an institutional solution and, unfortunately, the act of signing the contracts by a utility resolves many of those issues. It is over the decision to sign or not sign the contract that the resolution of those issues depends.

So we believe that this is not the time for Bonneville to demand utility acquiesce on these disputed issues on condition of continued participation in regional conservation programs. And we note in particular that we had until September 30 a situation which was working. It may not be the best long-term arrangement for conservation, but every utility or nearly every utility in the region was operating conservation programs in cooperation with Bonneville. The utilities were cooperating with the regional council, ratepayers were getting the service, and the region was getting the resource. And we have stepped back from something that we had achieved with some difficulty over the preceding months.

Mr. Chairman, I don't think I need to review for you the central role that the Regional Act places on conservation as a resource. It is a concern which the city of Seattle has had from the beginning, from the early deliberations on the act, and we were glad to see those concerns embodied in the regional act. It is clear from the act that conservation is a priority resource for the region, and we concur in that wholeheartedly.

We also agree that we should be pursuing conservation now. We agree with Bonneville and we agree with the regional power council. We will need a conservation resource in the future, and we know that it takes time to set these institutional arrangements in place and we have supported throughout the rate case the notion that Bonneville should be spending funds and acquiring resources even now, even in the time of surplus. We have no disagreement on that.

Mr. **Weaver**. Has Seattle signed its conservation contract with Bonneville?

Mr. **Fiddler**. No, we have not.

Mr. **Weaver**. Why?

Mr. **Fiddler**. For several reasons, Mr. Chairman.

First, I would like to say that our objective is to have an equitable and fair conservation contract with Bonneville. We have no interest in going it alone, and we have supported that in the plan and we have supported the BPA budget. We are continuing our own conservation program even in the absence of a conservation contract.

And, as my testimony indicates, in the absence of a financial benefit to the city of Seattle, in the mayor's proposed budget for City Light in 1984 and the revenue requirements analysis for 1985, we have included a substantial amount of self-funding for conservation. So we are not dismantling our programs. We are going forward with conservation, and the region will automatically benefit from that work.

We have not signed a contract for several reasons. First, financially, it seems to us to be a very, very bad deal for the city of Seattle and the ratepayers.

Mr. **Weaver**. Why?

Mr. **Fiddler**. Because of the contract charge, principally. The contract charge for Seattle in the test year would be about $2.5 million per year. This is a charge which would not be assessed if we brought a generating resource to Bonneville.

Mr. **Weaver**. How is it imposed?

Mr. **Fiddler**. The contract in section 32 gives authority to Bonneville to set a methodology to establish and collect a conservation contract charge for anyone who signs the contract and participates in the program. The contract charge is to be determined concurrent with the rate proceedings which we have just gone through, so we know what it will be only for the next 2 years.

Mr. **Weaver**. That is an up-front charge? They charge you $2.5 million, do they?

Mr. **Fiddler**. It is an annual charge. The methodology is in place in the Administrator's decision in the rate case.

Mr. **Weaver**. Why, Mr. Hickok, are you putting that in your contract?

Mr. **Hickok**. It is like a rate, Mr. Chairman. As a matter of fact, if we could fairly spread the conservation costs across the beneficiaries and utilize exclusively a rate mechanism, we would sure prefer to do that.

As Mr. Fiddler said, 1 year ago that is the method we employed, and we were in agreement with Seattle's position. But I would point out there were a lot of participants in our rate case who were vehemently opposed to Seattle's and our position. They were pointing out the generators, because they serve all or part of their loads with their own resources, were advantaged by a system where Bonneville made the conservation programs available to them across all their loads and yet recovered the costs solely in the rates for the sale of power to them. And some utilities there are placing no load at all on Bonneville.

Seattle happens to place about 25 percent of its load on Bonneville. But essentially they escaped 75 percent of cost associated with conservation that is being made available for their service territory, if we didn't employ a nonrate mechanism.

Mr. **WEAVER**. Do you employ the same kind of charge on generation?

Mr. **HICKOK**. There are two questions.

Mr. **WEAVER**. Do you or don't you, first of all? Answer the question first, then go on and explain it.

Do you make the same similar charge to generation?

Mr. **HICKOK**. Yes, we do.

Mr. **WEAVER**. All right, explain.

Mr. **HICKOK**. Because we charge, we have to recover our costs. Acquiring a generating resource incurs a cost. Acquiring a conservation resource incurs a cost.

Now, the question is, how are you going to raise the revenue to cover those costs? You raise those revenues for rates through rates and charges and fees the Bonneville assesses its customers.

Mr. **WEAVER**. Why don't you do the same with conservation then?

Mr. **HICKOK**. We are assessing. We are recovering conservation costs in rates and fees.

Mr. **WEAVER**. Do you charge—let's call this a fee—do you charge a fee for generation comparable to this conservation charge?

Mr. **HICKOK**. There are customer charges. There are demand charges and then there are rates for energy sold. The point is, Mr. Chairman——

Mr. **WEAVER**. Which is based upon the amount of power you buy, correct?

Mr. **HICKOK**. That is correct, because that was determined to be the basis on which they benefit. With conservation you are creating nonusers, nonbuyers, so the basis is—that was determined to have to be different——

Mr. **WEAVER**. The problem is that you really don't want conservation, Mr. Hickok, Bonneville.

Mr. **HICKOK**. Mr. Chairman, that is not true.

Mr. **WEAVER**. Bonneville has suppressed conservation in any way and every way it possibly can. Bonneville has constantly, continually suppressed conservation. And while you know the public wants it so greatly you have to pay lip service to it, which is about all you do——

Mr. **HICKOK**. Mr. Chairman, that is not true, and that is an unfair characterization of Bonneville's conservation effort.

Mr. **WEAVER**. Are you willing to say something on this, Mr. Fiddler? Has Bonneville been in your estimation a great champion of conservation?

Mr. **FIDDLER**. We have operated programs with Bonneville in the past.

Mr. **WEAVER**. Has Bonneville done all it could do to give us conservation, Mr. Fiddler?

Mr. **FIDDLER**. Mr. Chairman, we believe that it is very inappropriate for the conservation contracts to have expired, for that situation to have been allowed to occur. We think that is not in the best interest of the region.

I might add, sir, that my understanding of the way in which Bonneville would acquire a generation resource is that, if a utility, say Seattle, say Portland General Electric, any utility, puts load growth on the Administrator, the utility is obligated to offer to the Administrator a resource to cover that load growth. The offer would presumably be at the actual cost of the resource, and if the Administrator chose not to acquire it and to acquire resources from some other source, that would be fine. But I have never heard of a proposal under which Bonneville would assess a fee to the utility for bringing it that resource as a condition. It is simply not part of the arrangement.

Mr. WEAVER. Of course not, you are absolutely right. Just as I say, one more instance of Bonneville suppressing conservation. They do it directly, they do it indirectly, they do it overtly, they do it covertly. They suppress it in any way they possibly can and still get away with it within the public relations boundaries they must deal with.

I have seen it. I have had people come into my office time and time and time again and say that they can't get contracts of various kinds from Bonneville, whatever, and it is just a crying shame. We all understand why Bonneville does this. It is very simple. Mr. Hickok in effect just explained it.

Mr. HICKOK. Why? Why do we do that?

Mr. WEAVER. Because you won't get as much, won't sell as much electricity. And you are going to go like all the other utilities. You won't get as much, sell as much electricity, and that is what you are in the business to do. If you don't sell electricity, you won't be able to pay your bills.

Mr. HICKOK. That is not what we are in the business to do. We are in the business to serve the region and offset the future demand for electricity in the least costly way. We acquire power—conservation as a power resource. We do it cost effectively with available generation. We acquire the least cost resource first.

Mr. WEAVER. Mr. Hickok, that is exactly correct. That is what you should do, there is no question about it.

Mr. HICKOK. That is exactly what we do do.

Mr. WEAVER. In 10 years of monitoring BPA, that is exactly the opposite of what they have done.

Mr. HICKOK. Bonneville only has had this obligation since December 5, 1980.

Mr. WEAVER. I think, if you really were for the public, you would have had the obligation ever since you started. But again, that is illustrative of the Bonneville Power Administration's attitude. Only when forced by law are willing to pay lip service to it.

What is the status of BPA's effort to obtain sufficient funds for conservation from Treasury now, Mr. Hickok?

Mr. HICKOK. We have asked the Secretary of Energy to appeal OMB's decision, which was not to allow the full access to Treasury borrowing that we would need to cover our budgeted expenditures for fiscal year 1984.

Mr. WEAVER. Will you be able to implement the Council's plan if you can't get all the money?

Mr. HICKOK. We will not be able to implement it on the schedule that the Council and we have set out for ourselves.

Mr. WEAVER. Why has OMB refused to give you the money or allow you to borrow?

Mr. HICKOK. They have not offered a reason.

Mr. WEAVER. How many of the Council's 96 conservation actions is BPA going to be able to implement?

Mr. HICKOK. As I said, Mr. Chairman, I think we will be able to accomplish them all, but they are not on schedule—not in 2 years, in other words. There were some 96 conservation action items among the 115 in the Council's 2-year action plan. We would have to slip the schedule of quite a number of those, if we were not to have full access to Treasury.

Mr. WEAVER. The gentleman from Idaho.

Mr. CRAIG. Thank you very much, Mr. Chairman.

Mr. Hickok, there seems to be a difference of opinion on who is conserving or who is attempting to conserve more. I think it is somewhat like the argument that was placed a few minutes ago about geothermal. We dredged the records a little bit, recognizing BPA's role as was stated by Mr. Pollock of about $1 million dollars for fiscal year 1984.

I think that the broader picture does need to represent what the Government has done and, of course, BPA is a quasi-governmental entity. The record shows since 1972 this Government has spent about $1 billion dollars in assessing and developing geothermal. About $45 million of that was spent in my State. We got $45 million worth of holes in the ground at this moment that I guess the only value is if we could drag them out and cut them into 3-foot lengths, we could sell them to farmers for post holes. Other than that, they serve no real value.

Would you tell us, and for the record, since 1980, and I believe that is the year you used, of Bonneville's effort in the area of conservation, what you have done and the kind of money you have expended since that time, that represents the conservation effort you have been involved in?

Mr. HICKOK. We have spent since 1980 in excess of $300 million on the conservation effort in the Pacific Northwest. That includes a lot of program development work, a lot of the planning and pilot testing of the mechanisms that we later employed as programs to go after the conservation that we found to be available in the region. And that includes the acquisition of about 55 average megawatts, I believe, since the programs were first offered in the fall of 1981 on a region-wide basis.

We are budgeted to spend another $425 million, both in program design work, mostly the items that you know as 2-year action items, and in the acquisition of additional conservation through the weatherization, street lighting, and institutional buildings programs that will attain just about the Council's target of 155 total average megawatts since the conservation effort began.

I don't think there is any question that there is a lot of conservation activity going on in the region now as a result of Bonneville efforts that simply wouldn't have gone on had we never been involved.

Mr. CRAIG. Of that $300-plus million that you say you have spent since 1980, what have been the results of it besides obviously program development and those kinds of things? What have you been able to detect as a result of your effort to date?

Mr. HICKOK. I guess we saw as our principal mission the need to integrate conservation into a utility planning framework so that we could, by going in through our utilities, customers, and other entities, users of electricity in the region, acquire conservation as a power resource and set it up on a planning basis equivalent to a generating resource, so that we know how to spend money on it.

We would know how to evaluate. We could describe it in terms of its energy effect and capacity effect. We could describe it in terms of its reliability needs, a need for reserves, even the plant factor of the utility, of a conserving project and, therefore, so institutionalize it in the region that it would be universally accepted by the utility community which delivers electric power services to the region.

Now, we have done that, I believe, to a large extent, and we have also acquired in our, what I call our meat-and-potatoes-programs, the ones that actually go out and in the near term acquire the energy savings we have acquired, as I say, about 55 average megawatts.

Mr. CRAIG. I can appreciate some of the comments of my chairman, because I recognize what the mind-set, if you will, of utility companies has been historically, and until some of them were forced to, others came along and instituted conservation programs earlier and more voluntarily than others, and I have been an advocate of conservation for some time as a blend of the total energy picture.

Do you believe at this time, based on your studies and your expenditures to date, that it has been and will continue? Has been cost effective? And, if it has, will it continue to be based on the amount of money you plan to spend forward?

Mr. HICKOK. Absolutely.

The amount of money that we budget is a function of that least cost mix analysis that looks into the future to see how fast we have to develop these programs and how fast those programs need to acquire load reduction in order to make the most cost effective contribution to the future power supply.

We test that annually, continually.

Mr. CRAIG. You are able to test it?

Mr. HICKOK. Yes. In other words, our planning cycle consists of revising the load forecast, as we do annually, and then looking again at the value of surplus power sales and a number of other factors that would affect the short-term and long-term value of the conservation, and then rerun our least cost mix model which selects on a cost competitive basis the conservation programs or the generating projects according to their availability to us in time at a cost that we think we could obtain them in time. And we see how the conservation program as a whole shakes out of that.

So we are continually redefining our targets.

For example, 1 year ago we believed we were moving on a path to acquire about between a 1,000 and 1,100 average megawatts of conservation by 1990. We revised that to place the conservation effort on a path that will produce between 600 and 700 average megawatts, because our load forecasts are falling, short- and long-term, and the value of surplus sales, as Mr. Pollock has already described, plummeted recently.

We are for a period of time, anyway, fully loading the interties to the Southwest. We will take another look at it again as we go through another planning cycle. The long-range targets, therefore, remain fluid.

What that says about our short-term budgeting is that it either accelerates or decelerates our current program effort, but our program effort is entirely responsive to long-term need for power.

Mr. Craig. Is there a point of diminishing return? Have you been able to determine that as it relates to the amount of money you have put into the conservation effort?

Mr. Hickok. I think that the way we would describe that is that any amount of money you would expend on conservation in excess of spending what it would take to produce that 600 or 700 megawatts by 1990 would not be in the interest of the ratepayers. In other words, it produces a present value of the cost of that future power supply that is higher than the present value you get by running the program at about a 600 or 700 megawatt clip on a 1990 basis.

In other words, we are trying to minimize absolutely the cost of that cost mix of resources in the future. Also, spending less than we are spending today is also not beneficial to the ratepayers. We believe we are at the pace where you produce that optimal result.

Mr. Craig. Thank you.

Mr. Weaver. You made a statement that 70 percent of the electrically-heated homes under Bonneville are not qualified for your conservation program, your total conservation program; is that correct?

Mr. Hickok. The total program. They are all eligible. All electrically-heated houses are eligible for the program, but——

Mr. Weaver. In effect, 70 percent of the electrical homes are not eligible for your total program, is that correct?

Mr. Hickok. That is correct. They are not eligible for the anti-air infiltration measures, which would account for perhaps one-quarter of the available energy savings in weatherization. So our measures in those houses are getting three-quarters of the available savings.

Mr. Weaver. Mr. Fiddler, how about Seattle, how many?

Mr. Fiddler. Our program people believe that, perhaps because of the age of Seattle's housing stock, about 95 percent of our homes are not eligible for those measures.

Mr. Weaver. Not eligible?

Mr. Fiddler. That is right, principally for storm windows.

Mr. Weaver. Why?

Mr. Fiddler. Because they would have BPA's——

Mr. Weaver. I am talking about you, Seattle, yours.

Mr. Fiddler. In our programs? They are eligible for those under our programs.

Mr. Weaver. Seattle has everybody eligible?

Mr. Fiddler. That is right.

Mr. Weaver. Bonneville has 30 percent eligible. I am trying to make the comparison here. I want apples and apples.

Mr. **Fiddler**. That is correct, Mr. Chairman. We reviewed the same question when Seattle was developing its own independent program for home weatherization before we were developing it concurrent with the passage of the Act. So we had reached these questions on our own, and we chose a different path that didn't exclude homes from the measures but, rather, disclosed the damage, the potential for increasing pollution sources to our customers. We felt that was the best approach based on a fairly comprehensive review we did.

Our main reason for that, if I may add, was that we felt that the utility couldn't really take responsibility for the level of pollution sources in a home. It has to do with how the home is built, what the owner introduces to the home, how they keep the windows and doors open. That is something that basically the homeowner must manage, because we cannot.

Mr. **Weaver**. That is the sensible approach, Mr. Fiddler. How can you sit here and say you don't suppress conservation, Mr. Hickok? It is unbelievable. You do actually. Bonneville has a very dramatic conservation program. Do you know why Bonneville has a very dramatic conservation program? Because it is a farce and a tragedy. It is just ridiculous.

Any further questions?

What is the load growth, Mr. Fiddler, the Seattle City Light load growth actually the last few years.

Mr. **Fiddler**. I could provide an answer on that for the record. I believe it has been in the 1- to 2-percent range.

Mr. **Weaver**. Thank you very much. I appreciate both of you coming.

The chair would like to call Mr. Paul Hathaway, vice president, Northwest Natural Gas Co.

It is always a pleasure to have you back here with your good counsel. You have a statement. Won't you give it to us, please?

[Prepared statement of Paul Hathaway may be found in the appendix.]

STATEMENT OF PAUL L. HATHAWAY, SENIOR VICE PRESIDENT, NORTHWEST NATURAL GAS CO.

Mr. **Hathaway**. Thank you very much.

For the record, I am Paul Hathaway, senior vice president of the Northwest Natural Gas Co. of Portland, OR. You invited our president, Mr. Miller, to come back, and he sends his sincere regrets. He really did want to be here himself to express his concerns about the Northwest Power Planning Council's energy plan.

I do have a prepared statement and I would like to read parts of it, if I may, sir.

Mr. **Weaver**. Please do.

Mr. **Hathaway**. Let me say at the beginning, though, that my comments regarding the regional energy plan reflect not only the views of my company but also those of the other natural gas distribution companies that serve the Pacific Northwest region and the pipeline company that serves all of us, the Northwest Pipeline Corp.

Our industry participated very actively before the Regional Power Council during the 2-year period when the regional plan was being prepared. Besides offering oral testimony and exhibits on a number of occasions, our industry remained in continuous contact with the Council's technical staff.

Before discussing the specific concerns with the programs and the plan, I would like to give you a very brief picture of the present and possible future role of natural gas in the regional energy picture.

The current magnitude of the regional natural gas industry can best be expressed in some numbers. There are more than 758,000 residential, 186,000 commercial, 3,300 large industrial natural gas customers in the region. The total natural gas sales in 1982 equalled about 282.4 billion cubic feet. The supply backing up those sales was more than 573 billion cubic feet. So we have only used about half of the supply that is plentifully available under contract in our current demand.

The regional gas sales, in 1981, for a comparative basis, were 1.32 times the 1981 sales of the Bonneville Power Administration on an energy basis.

Mr. WEAVER. Could you tell us where in your written testimony you are?

Mr. HATHAWAY. I am reading now just some figures that are contained in an addendum to my testimony. I am sorry, I was skipping around a little bit in order to be brief but to give a little bit clearer picture of the natural gas industry in our region.

This was contained on page 8 of testimony that was presented in June to the Subcommittee on Energy Conservation and Power. It is just to make and reiterate the point of the importance of the natural gas industry and its ability, to provide energy services in the region and its ability, by the way, to be able to sell conservation to Bonneville at no cost.

At the present time, the regional residential gas prices are competitive with the electric prices of the private electric utilities. As a result of the recent electricity price increases and the price increases of the current Bonneville Power Administration ratemaking proceedings, the regional natural gas residential prices are becoming competitive even with the regional public utilities.

In summary, the natural gas distribution industry in the Pacific Northwest is in a very healthy condition. We are in excellent position to compete with other energy forms in the marketplace, and that is really what we would like to do. We would like to be able to do it on a fair basis without the unfair competition of subsidies coming in part from the regional power plan.

Mr. WEAVER. I notice that you say on page 5 of your summary testimony that "Our industry has provided undisputed proof that the plan's model conservation standards for new residential and commercial buildings are not cost effective for natural gas heated structures."

Mr. HATHAWAY. Yes sir.

Mr. WEAVER. Would you explain that? You are telling somebody it is going to be hard to convince. I am a great believer in natural gas. I have it in my own home. I have kept my stringent conservation program. I put it in my home. I have kept my bills between $5 and $15 a month, except they go to about $20 in mid-winter. I have 2,500 square feet.

Mr. HATHAWAY. Well, the form of the model standards is based on energy input basis, and for natural gas the structure of the standard, if it were applied across the board to a residence heated by either electricity or natural gas or oil, simply wouldn't work. It would not be cost effective, in that we would not be able to afford to provide natural gas service to a home constructed to those standards. The Council itself has admitted that the standards don't comply that way and that there in fact should be two standards based on the particular fuel chosen by the user.

Let me return briefly to my prepared comments, if I may.

Mr. WEAVER. Sure.

Mr. HATHAWAY. The theme that we have followed throughout all of our presentations to the Council in testimony, when the plan was being prepared, says simply that the gas industry would find intolerable and would vigorously oppose a plan that provided financial subsidies and incentives and other inducements to customers and others to switch to electricity as a source of energy or to choose electricity in the first instance.

We categorically repeated our industry's disagreement with any program or energy policy which signaled any preferential treatment for electricity. Aside from the obvious anticompetitive interference that such programs or policies would impose on the energy market, and the hindrance they would cause to the economic well-being of the region's ratepayers as a whole, the effect of those programs or policies would clearly be opposed to the purpose of the Pacific Northwest Electric Power Planning and Conservation Act.

That act demands load reduction through conservation of electricity. The financial incentives that appear in the plan, on the other hand, guarantee electric load increases even though they are offered under the guise of purchasing conservation.

The regional plan was adopted in April 1983, and our industry was appalled at the clear favoritism shown the electric energy industry and the clear anticompetitive and discriminatory interference in the energy marketplace. Accordingly, our industry filed a lawsuit on July 28, 1983, which was a petition for review in the U.S. Court of Appeals for the Ninth Circuit, in San Francisco.

Mr. WEAVER. Would you give us some detail on this discrimination?

Mr. HATHAWAY. Yes sir; I will in what follows.

I have included in my testimony as an addendum the entire petition. It has 14 separate points of contention on the plan. It is important to note, though, that the petition does not challenge the Regional Power Act. But it does challenge the action of the Northwest Power Planning Council as it is promulgated.

The respondents include the Council members, the Administrator of BPA, and the Secretary of Energy. The latter two are named because of their obligation to implement the plan.

The petition seeks a declaration from the court that certain programs required by the plan violate the Regional Power Act, and it also requests an injunction against those programs which our industry considers to be most harmful.

The petition also asks the courts to remand the plan to the Council for rewriting in accordance with any findings that the court may make.

Let me stress two points that I think are germane here. First, the natural gas industry is certainly not opposed to conservation of energy. We support the policy and have demonstrated that commitment consistently and strongly through our own conservation programs.

The natural gas industry is against the payment of financial incentives and subsidies by the BPA for the purpose of influencing customer choice of energy forms. This means that our industry also does not want such incentives to be paid by the BPA to induce customers to choose natural gas either. We merely want to be allowed to compete on an equal basis in providing services to the consumers of the Pacific Northwest.

There are three main issues that we raise in the petition. There are 14 actually, but three main ones:

First, we believe the plan violates the Regional Power Act by calling for the payment of the first cost of electric boiler installations for industries presently using fossil fuel boilers. Providing for the special rates, which may be noncompensatory, all for the purpose of marketing interruptable electric energy in the plan is particularly offensive in that respect, because it sets a long-term discriminatory policy couched in terms of the purposeful displacement of fossil fuel boilers.

The Council has responded that it did not intend to convey the impression that it supports noncompensatory electric rates, but we remain concerned that this highly influential energy planning body has quite improperly conveyed the impression in its plan that displacement of fossil fuels is the preferred energy policy for the region. We feel this unacceptable impression must be corrected.

A second point: Our industry has provided, as you mentioned earlier, undisputed proof that the plan's model conservation standards for new residential and commercial buildings are not cost effective for natural gas heating. The Council has acknowledged that it didn't study the cost-effectiveness of the model standards for structures utilizing natural gas for space heating. Indeed, in volume 4 of the plan, the Council acknowledges that, if the model conservation standards were applied to all new structures, that is to say, a single code applicable to all of them, the most likely result would be more homes using electricity for heating.

The estimated electrical load increase would be on the order of 300 megawatts. Yet, in appendix J to the plan, which is the most likely document that local governmental implementors will look to in adopting the model standards, it does unquestionably apply to structures using natural gas as well. We have pointed this out to the Council staff, and we are hoping that we can resolve this one by negotiation.

Finally, our third point: The petition identifies a number of problems in the plan which are fraught with anticompetitive aspects and which, if implemented by BPA, do irreparable harm to our industry and consequently the region's economy. The basis of these claims is the Regional Power Act definition of the word "conservation." Section 3 of the act defines conservation to be the reduction in electric power consumption as a result of increases in efficiencies of energy use, production or distribution.

Our industry maintains that, where the use of natural gas is more cost effective to the region for a given purpose than the use of electricity, and when such use reduces electric power consumption, then the use of natural gas in those instances would be conservation.

The BPA, however, insists that natural gas use is not and cannot be conservation. Rather, BPA insists that natural gas is the last priority resource under the scheme of resource purchases set forth in the act. I think Bonneville's position defies logic as well as defying the act. What better means of conserving electricity is there for the region than to increase its availability by substituting natural gas for it in those uses where natural gas is most cost effective?

Since our industry is not asking for any financial incentives and indeed, they are opposed to them, how is the use of natural gas then not cost effective?

Yet, the use of natural gas as a substitute for electricity was not considered in the plan. There was no consideration of the cost-effectiveness of the voluntary use of natural gas in the plan to substitute for and hence to conserve electricity. We will be happy to sell conservation in the form of natural gas use to Bonneville at no cost.

Frankly, we fear BPA's position is motivated by two overpowering concerns. First is BPA's concern that, if natural gas is treated as a conservation measure, BPA will have to pay for the installation of natural gas equipment and for the fuel itself. Our industry's position against such subsidies certainly should dispel that fear.

Second, BPA is concerned about the present short-term electric energy surplus. Bonneville feels that it is in its best interests and also in the best interests of its utility customers to aggressively market all the electricity it can in the region during this surplus period, thus leaving no room for conservation measures utilizing natural gas.

The natural gas industry does not oppose an appropriate method of utilizing electricity as a resource to help our region regain its economic health. Indeed, we favor healthy marketing efforts by all energy distributors. On the other hand, interference in free marketplace decisions of energy consumers through the injection of financial subsidies favoring one energy form over another, we believe, will wreak havoc with our region's economy. We are absolutely confident that the court will not countenance these programs which favor one industry at the direct expense of another in the same market.

In your letter to Mr. Miller of our company, Mr. Chairman, you also invited comments on the Administrator's September 30, 1983, decision establishing new rates and on H.R. 3177, the Bonneville Power Administration Fair Rate Making Act of 1983.

We did not participate in the 1983 BPA rate case, although we did participate to a limited extent in the 1982 BPA proceeding. Consequently, I feel constrained not to comment on the subject of the 1983 case. At this time we are studying the various new interruptible rates issued by the Administrator. We recognize that the proposed 7 mill per kilowatthour surplus energy rate will contribute to an already distinctly competitive environment in the industrial sector for natural gas. We are not now in a position to say that such proposed rate is or is not compensatory. We can categorically say, however, that it would be immeasurably harmful, and certainly illegal, if BPA were to pay the first cost of electric boiler installations in addition to providing electric energy at such a low rate.

On June 13, 1983, I had the opportunity to appear before the U.S. House of Representatives Subcommittee on Energy Conservation and Power of the Committee on Energy and Commerce, in Seattle. At that time, I expressed our industry's support of H.R. 3177. I am taking the liberty of providing your subcommittee five copies of the testimony I presented then, for it addresses H.R. 3177 as well as other matters relating to the conduct of BPA's rate proceedings. I hope those comments will assist you in your consideration of the bill.

Again, thank you for your invitation to participate in these hearings. We are glad for a chance to present the natural gas industry's views on the energy situation in the Northwest.

Mr. WEAVER. Thank you. They are very helpful and valuable additions to the testimony that we received in these hearings. They present a view that must be part of the picture. You have answered in your testimony most of the questions.

I would like to know a few details on how the Council's building standards encourage installation of electric heat in new residences?

Mr. HATHAWAY. Let me refer to our petition where we have set that forth.

Mr. WEAVER. It is in the petition?

Mr. HATHAWAY. Yes, sir. It is included in some detail.

Mr. WEAVER. We can glean it from there.

Mr. HATHAWAY. Yes, sir.

Mr. WEAVER. Is it more efficient to heat space and water with electricity or gas?

Mr. HATHAWAY. Excuse me?

Mr. WEAVER. Is it more efficient to heat space and water with electricity or gas?

Mr. HATHAWAY. We maintain that it is far more efficient, if you are comparing resources, to heat space with gas than it is with electricity.

Mr. WEAVER. Why?

Mr. HATHAWAY. If you compare a fossil generated electricity, as an example, the best of the generating stations, generally speaking, would probably have an overall thermal efficiency of something on the order of 40 percent, perhaps less. You add transmission losses to that for another few percent and perhaps you will wind up delivering something under perhaps 35 percent of the energy available in the resource that you started with, when it is delivered to the end user as heat.

In delivering natural gas to the consumer you deliver the resource directly, and in some of our newest gas heating units, the efficiencies are as high as 97 percent overall. Some of the condensing furnaces are reaching up in the 85-percent range for water heating. So, in effect, if you are comparing 95-percent delivery of the energy available in the resource to the consumer as usable heat, compared with something under 40 percent, you can heat two homes for the amount of energy compared to only one if you change that energy form into electricity.

Mr. **Weaver**. Very good.

Nevertheless, what has happened to the use of natural gas in the Northwest in the last 10 years?

Mr. **Hathaway**. It has declined as a total.

Mr. **Weaver**. Why? How do you explain that?

Mr. **Hathaway**. Well, part of it is a very interesting conservation effect that we have observed that has been in large part due to the cost of energy. We observed, for example, in the years from 1973–77—I will take that because it is a figure I know handily—but those years were when the price of our Canadian ration of gas rose about sevenfold, from 3 cents a therm up to 21 cents a therm at the border.

During those years, we observed our customers' use, unit use of natural gas, declined by 35 percent, a direct conservation effect, because when the gas bill went up, the thermostat went down, and that has continued.

With the adding of conservation programs in the early 1980's, we have seen the conservation effect continue. The price has also been rising. We are down now to where our residential customers on the unit basis are using about only 55 percent of the natural gas that they used in the early 1970's. That is an enormous conservation effect that we have seen. We welcome that, because it does mean that our reserves are better, we can serve more people, and that we will have a longer reserve life for our gas supplies.

Mr. **Weaver**. I only wish Bonneville Power Administration had understood that simple fact of economic life. Lord knows, I tried to tell them that, but they never got it through their noggins. You were in the enviable position, however, where the production of natural gas did not require huge plants?

Mr. **Hathaway**. That is correct.

Mr. **Weaver**. Therefore, you came out of it quite well. You did not have the WPPSS tragedy.

Mr. **Hathaway**. We do not have the large capital investment requirement that generating stations involve.

Mr. **Weaver**. Your prices are now going down a bit, aren't they?

Mr. **Hathaway**. We are seeing price decreases. The Canadians have dropped their price, as you know, from $4.94 a million Btu at the border down to $4.40, and they have recently offered a further drop on an incentive basis. It is down to $3.34 per million Btu for volumes taken over and above some contract limits of the pipeline.

I am encouraged in our discussions with the Canadians and with our own Department of Energy in the negotiations that are going on now that we will be able to get in place a policy with Canada that will allow independent pipeline negotiations that will provoke lower prices in order to be competitive.

Mr. **Weaver**. The gentleman from Idaho.

Mr. **Craig**. Thank you, Mr. Chairman.

I appreciate your testimony, Mr. Hathaway, and what you have said I can certainly concur with, in watching our own gas distributor in Idaho and the effects that pricing has had on conservation.

Can you say in large part, though, that that change in residential demand and a drop of some 35 percent of use from a base date of when—somewhere in the 1970's—1975?

Mr. HATHAWAY. I am sorry.

Mr. CRAIG. You mentioned that you had had a conservation effort equivalent to a 35-percent reduction from a time——

Mr. HATHAWAY. The time that I used was beginning in 1973.

Mr. CRAIG. 1973?

Mr. HATHAWAY. Yes, sir.

Mr. CRAIG. 1973. We know what happened as it relates to natural gas and its price. At that time, was the industry launching a major conservation effort also?

Mr. HATHAWAY. We were not engaged in a major conservation effort at that time.

Mr. CRAIG. What you are telling me, then, is that a larger portion of the conservation that has come about has a direct result of pricing?

Mr. HATHAWAY. That is correct.

Mr. CRAIG. Much more so than a massive effort on the part of your companies to promote certain types of conservation efforts?

Mr. HATHAWAY. Absolutely; the single most important factor that we have noted is the cost of energy to the consumer. That brings about the conservation action on the part of consumers, whether it is insulating or turning down the thermostat and wearing another sweater, or simply putting a setback thermostat in, or whatever those efforts are. The customer does it voluntarily on the basis of reducing his cost.

Mr. CRAIG. I think that is an important point and I think the record needs to show that. Because some here today have been criticized for not launching a conservation effort, and I think that the marketplace demonstrates that price and conservation can and do go hand in hand, and the gas industry has to be the prime example of that. I don't think anybody would have advocated way back in 1973 that BPA artificially start jumping its prices up for the purpose of evoking some kind of conservation effort on the part of the consumer, would they?

Mr. HATHAWAY. No; I don't think so.

Mr. WEAVER. Would the gentleman yield? I did.

Mr. CRAIG. I know you did, and I think you were wrong, Mr. Chairman. That is not the point. The point is that, when the marketplace demands a level of use and a cost of energy is in relation to that, conservation, or the cost of industry and conservation, there is some elasticity there that offers a good example of what has gone on with the gas industry.

Mr. WEAVER. Would you yield?

Mr. CRAIG. Yes.

Mr. WEAVER. Let me explain why I did. Because what you had in 1973-74, was that, as the price of electricity went up, we would use less, but the price wasn't going up unless these enormous, expensive plants were built. Now, there was a dilemma then facing—I wish it had faced Bonneville and others that didn't perceive it—but it certainly was excruciating to me, and the dilemma was this:

If we built the plants, we didn't need them. If we built the plants, electricity would become so expensive that demand would drop, and you wouldn't need them. If we didn't build the plants and electricity stayed cheap, we would need them. So that was the dilemma.

How do you get around it? I got around it by promoting a two-price system—the more use the higher the price—so that the market would work, revenues would remain the same. The first amount of electricity would be very cheap for basic essentials to both business and residences. Then the price would have gone up sharply to have anticipated the rise in cost of electricity by building the plants. So it was a market device I used.

Now, you say I am wrong. I don't think so. I think that would have saved the Northwest $10 billion.

Mr. CRAIG. Well, it is not a question of being wrong. Maybe you were before your time in that instance. I am suggesting that the industry on the whole and certainly the consumer tends to allow the marketplace to work its will. In this case it did. I am not going to argue whether there should be five thermal nuclear facilities built. I think that is where the foolishness rested of get it completed, get it on line. Bring it in gradually. That is going to allow the marketplace to move, and you would have seen I think—but that is all in the past.

You did make a statement or several, and I appreciate your analysis and your concern that natural gas was not built into the Council study as an overall energy part of the mix as it relates to the plan, and I think those arguments certainly have some validity.

You make a statement that first quick-fix attempts to remedy existing electrical energy surplus by policies causing electrical energy dependence should be condemned.

Now, I think you have given some example of that. Do you wish to broaden that?

Mr. HATHAWAY. I think the most obvious example is the subsidizing in one way or another the installation of an electric boiler along side an existing fossil fuel boiler for the purpose of selling surplus low-cost electricity. To me, you are duplicating a rather high-cost capital installation. You are doing this on the basis of a relatively short-term availability of surplus electricity. Certainly it is not going to be available the year round, and it is questionable, in my mind, how long the surplus will last. If you had a couple of dry years back to back and some cold winters, I wonder how much surplus would be available and whether that electric boiler would sit there idle or not.

If I look at the other side of the question, once a user installs that equipment, he wants to use it, and to me it is a potential additional permanent electric load added to the system. I think we are really caught in a bind here. We are trying to comply with an act that calls for conserving electricity in the midst of a short-term surplus and trying to get rid of the surplus at the same time. Things like this are really looking at the quick-fix solution but may wind up with a permanent additional load, and that is what we are concerned about.

It also takes away from the fossil fuel load, which is serving the customer pretty competitively under the normal rate, and that means added cost to all of the rest of the fossil fuel users, our other natural gas customers, because the industrial load carries a fair amount of burden of the fixed costs of our gas plant. So the residential and commercial customers would then have to pick up those fixed costs that are taken away by the installation of these electric boilers.

Mr. Craig. Let me conclude with asking you—I guess my last question would be, based on what the industry, your industry knows now, and relationships and new relationships that are currently underway with Canada, what do you believe your future is as it relates to availability of supply to you long term, and can you see yourselves, based on availability of supply and consumer demand, being in a very competitive or a reasonably competitive position for some period of time down the road? Are we looking at 10, 15, 20 years, a quarter of a century, half a century?

Mr. Hathaway. I think we are going to be in a very good competitive position for the next several decades at least, and beyond that.

The present supplies that are under contract—this means reserves that are known, developed and onstream, serving the Pacific Northwest—cover about 23 years of reserve life index. That is to say 23 years of use at present rates, including a nominal rate of growth in customers. That is less than 2 percent annual average growth.

Mr. Craig. Your projected rate of growth is less than 2 percent?

Mr. Hathaway. We have used some figures in the addendum to my testimony——

Mr. Craig. I wonder what you term a reasonable scenario?

Mr. Hathaway. We think currently that approximately is a reasonable scenario.

Mr. Craig. You are looking at——

Mr. Hathaway. Looking at that kind of potential load growth. If you compare that with a higher figure, for example, the supplies that we have under contract, we could double that load rate and still be able to serve those customers out to year 2000 with the supplies presently under contract.

Mr. Craig. What would the price be then?

Mr. Hathaway. The price, as I see it at this point, is going to be quite stable for the next few years. I would hesitate to project price much out beyond a couple of years, because our price depends on our competition from oil in the industrial market, from electricity in the——

Mr. Craig. You talk about a relatively stable price based on the 2-plus percent growth you mentioned. Even if it doubled you could still offer an availability of supply?

Mr. Hathaway. Yes, sir.

Mr. Craig. Have you been able to equate what the price would be? Are you seeing a doubling of price?

Mr. Hathaway. No, I don't think so. I don't think that is in the cards at all. I think our price ultimately is going to track competitively with the other energy forms. It does now. We have seen the price drops we see coming out of Canada as a result of direct competition of oil in the industrial market. In Canada in their last price increase exceed the cost of residual oil that serves a big part of Northwest industrial market. When all the industry went from gas to oil, all of the gas stopped flowing across the Canadian border and hit them very hard.

That is why we are seeing the price reductions that we have seen, and I think we will see more. Those reductions on the Canadian side are going to stabilize our price in the region for quite a few years, I believe. I can't put a figure on it.

Mr. **Craig**. Thank you.

Thank you very much.

Mr. **Weaver**. I thank you very much, Mr. Hathaway. We appreciate your testimony.

I would like to conclude the hearings by saying something you won't expect me to say, and that is that Bonneville Power Administration does have the largest conservation program in the United States. It is called WPPSS, the enormous cost of WPPSS.

With that, the hearing is adjourned.

[Whereupon, at 1:10 p.m., the subcommittee was adjourned.]

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APPENDIX

THURSDAY, OCTOBER 27, 1983 AND FRIDAY, OCTOBER 28, 1983

ADDITIONAL MATERIAL SUBMITTED FOR THE HEARING RECORD

STATEMENT OF CONGRESSMAN CARLOS J. MOORHEAD

Congressman Weaver, I wish to thank you for this opportunity to speak to you and address the Subcommittee on matters of concern to me and the District I represent.

As you know, the Bonneville Power Administration is the federal Power Marketing Agency for the Pacific Northwest and engages in surplus nonfirm sales of its energy and capacity to the Pacific Southwest. This interaction works to the mutual benefit of both regions. We, in the Pacific Southwest, are appreciative of this interaction and look forward to its continuance.

However, there are significant areas of concern that I would like to call to your attention.

As you are well aware, the nonfirm sales offered by Bonneville are governed by federal laws which contain some marketing restrictions. These enactments were intended to benefit and protect all people in all regions of the country. But it appears that the Bonneville Power Administration in its operating practices has been hesitant to offer nonfirm energy to the Pacific Southwest when it had such energy available. This has occurred even with energy that had been offered first to the Pacific Northwest and subsequently declined. The purchase of this energy by the Pacific Southwest, if offered by Bonneville, would have added to the Bonneville's revenue recovery.

Bonneville has proposed new rate schedules which will charge members of the same customer class different rates for the same type of energy, i.e., energy produced by the same resource. Bonneville states that its nonfirm rates are based upon the cost of providing such nonfirm service but has never performed a cost-of-service study to identify the actual costs incurred in producing this nonfirm energy.

Bonneville has also proposed, in addition to the normal cost-based intertie transmission rate, a separate Southern Intertie access charge for the non-BPA energy. This additional charge could cause concerns in the Pacific Southwest as to the economic visibility of long-term Pacific Northwest transactions. Proposals such as this have a potential adverse impact on Pacific Northwest revenues because of possible lost sales to the Pacific Southwest. Also, this surplus hydroelectric power would have provided a clean economical source of electrical energy for the Pacific Southwest.

However, the Pacific Southwest believes that it is still possible to conitnue in its business relationship with the Pacific Northwest and contribute to its economy. Because of the existence of surplus energy in the Pacific Northwest and available markets in the Pacific Southwest, there exists an opportunity for continued, and possible expanded, interactions.

Thank you again for extending this opportunity to address you, Congressman Weaver, and the Subcommittee.

Before the

U.S. HOUSE OF REPRESENTATIVES

SUBCOMMITTEE ON MINING, FOREST MANAGEMENT
AND THE BONNEVILLE POWER ADMINISTRATION
of the
COMMITTEE ON INTERIOR AND INSULAR AFFAIRS

HON. JIM WEAVER, CHAIRMAN

Statement of
ROBERT GREENING, MANAGER
PUBLIC POWER COUNCIL

October 27, 1983

The Public Power Council appreciates the opportunity to testify before this subcommittee. The Public Power Council represents the Pacific Northwest's consumer-owned utilities on power supply, planning and ratemaking issues. These 115 municipalities, PUDs and cooperatives are Bonneville's preference customers. About 10 of these preference customers have some generation; the remainder are completely dependent upon Bonneville for their entire electric power supply. PPC was formed in 1966 to represent and advocate the common legal and technical interests of these preference customers when dealing with Bonneville and with other regional and national groups.

In this capacity, PPC works with a broad range of issues, including BPA wholesale power rates, other BPA policy issues and implementation of the Regional Power Act. It was through the Public Power Council that Pacific Northwest preference customers helped to draft and lobby the Northwest Electric Power Planning and Conservation Act.

THE BALL GAME HAS CHANGED SINCE THE PASSAGE OF THE REGIONAL POWER ACT

Since the passage of the Act of 1980, the conditions in the Northwest have changed dramatically. One of the underlying premises of the Act, for example, was to provide the region with the planning tools to deal with the looming power deficits. Today, three short years after the passage of the Act, we are instead facing substantial power surpluses which extend to the end of the decade.

The causes of this remarkable turnabout are simple: WPPSS and the recession. The enormous increases in the cost of the WPPSS net-billed plants have caused BPA's rates to soar. These higher electric rates, coupled with the recession, have caused large decreases in electric loads throughout the region. Northwest residential, commercial and industrial ratepayers have simply stopped using as much electricity, whether through conservation, curtailment or fuel switching.

Perhaps better than anyone else, your Chairman, Mr. Weaver, predicted the course of events flowing from the WPPSS cost increases. This committee must keep this dramatic turnabout in mind when evaluating BPA's performance in repaying the federal debt, setting rates, evaluating resources, and offering conservation programs.

BPA IS ON THE RIGHT COURSE IN SETTING ITS RATES AND IN MAKING UP ITS FEDERAL DEBT PAYMENTS

While no one likes rate increases and some object to portions of every BPA rate proposal (see Public Generating Pool Statement), PPC believes that BPA is making great strides in putting BPA on a sound financial course. The agency has greatly improved its load, revenue and cost forecasts, making future federal debt deferrals highly unlikely. BPA has, with its customers' support, included in its latest rate proposal provisions for repayment of all deferred federal debt principal and interest. PPC therefore believes that BPA's repayment performance is well under control.

THE RATE CEILING IS THE REGIONAL POWER ACT'S PRINCIPAL PROTECTION FOR BPA'S PREFERENCE CUSTOMERS

Certainly Chairman Weaver will recall that BPA's preference customers were reluctant participants in the passage of the Regional Power Act. Eugene Water and Electric Board, Chairman Weaver's own utility, and several others actively opposed the Act. The Rate Ceiling (Section 7(b)(2)), more than any other part of the Act, swayed most preference customers toward support. PPC is therefore quite concerned that the protection envisioned by that provision be retained.

The investor-owned utilities and the direct service industries acknowledged and accepted the risk that the rate ceiling could "trigger" and throw "supplemental rate charges" onto their rates (Section 7(b)(3)). BPA cannot abandon this protection for its preference customers merely because circumstances have changed. This change in circumstances is precisely the situation for which the rate ceiling was designed. Simply put . . . BPA, the IOUs and the DSIs accepted the risk that the Act might not be so beneficial when they agreed to the rate ceiling for us.

This committee should ensure that BPA follows the law in establishing a rate ceiling methodology. Preference customers agreed to a contract extension to March 1, 1983, to give BPA more time to establish the methodology through a Section 7(i) public proceeding. We have strongly insisted that BPA fulfill this contractual obligation. We hope that both BPA and this committee are committed to making good on the Act's promise to protect our rates.

CONCLUSION

The Public Power Council and its member utilities look forward to assisting this committee in its oversight function.

XI:2:05

October 27, 1983

Public Power Council's Answers
to
Questions for Northwest Publicly-Owned Utilities

1. BPA's final studies for the 1983 rate proposal show an expected Operating Year (OY) 1985 scheduling publics load on BPA of 966 average MW (aMW), compared with a FY 1983 scheduling publics load of 464 aMW. This represents a 108% increase over a period of less than 2 years. Is 966 aMW a reasonable projection of the OY 1985 scheduling publics load on BPA? If so, how will this additional load on BPA affect (1) the marketing of nonfirm surplus energy by the scheduling publics and by other non-BPA utilities in the Northwest, and (2) the overall revenue these utilities need to collect from their retail customers?

The 966 aMW projection is reasonable. BPA's revenue forecast projects that the total load of the generating publics will rise just 5.1 percent between 1983-84 and 1985-86. (See pages 36 and 37 of BPA's Final Loads and Resources Study.) The question is therefore aimed not at the rise in total generating public loads, but at an apparently large increase in the loads generating publics will put on BPA during OY 85.

The 108 percent increase is due in part to the inclusion of Cowlitz, Grant, and Douglas PUDs in the OY 1985 list of scheduling publics, and the exclusion of those three PUDs from that list in FY 1983. (See pages 96 and 97 of BPA's Final Documentation for Revenue Forecast for Reconcilement.) For example, during the 5-month period from October through February in FY 1983 for which reconciliation information is available, the scheduling publics' load is 691 aMW without the three PUDs and 1092 aMW with the PUDs, a rise of 58 percent. The rise for the whole year would be significantly greater than 58 percent since the spring runoff comes after this period. During the spring runoff generating publics offset their purchases from BPA with secondary hydro. PPC staff has therefore estimated that at least 75 percent of the 108 percent increase results from the inclusion of the three PUDs.

The remaining percentage increase between FY 1983 and OY 1985 in BPA sales to scheduling publics is the result of the "ratchet" Bonneville imposed in the 1983 rate case, which makes it uneconomic for generating publics to use their secondary to offset BPA purchases. This effectively transfers secondary from BPA to the generating publics. The effects on retail rates of these generating publics will depend on the utilities' success in marketing this transferred secondary. PPC notes that the generating public utilities believe that the "ratchet" violates their power sales contracts with Bonneville.

2. Recent BPA reports show that, starting in 1987 and continuing thereafter, BPA expects the Industrial Firm rate to be lower than the Priority Firm rate. Would such a relationship between these two rates be consistent with the Regional Act or its legislative history?

No. After 1985, the Regional Act (§7(c)(2)) mandates an appropriate markup for the Industrial Firm rate over the Priority Firm rate. Even after the value of reserves is deducted from the Industrial Firm rate, we feel that the Priority Firm rate will still be significantly less than the Industrial Firm rate. (Within the Priority Firm rate class, BPA's preference customers receive additional rate protection due to the rate test, of course.)

The estimates that the Industrial Firm rate are lower than the Priority Firm rate are based entirely on a BPA computer program called the Supply Pricing Model (SPM). PPC staff has determined that this undocumented model contains serious conceptual errors which lead to incorrect results.

3. Should BPA interpret the Regional Act §7(b)(2) rate test and §7(c)(1)(B) rate methodology in a manner that could jeopardize the existence or value of the residential exchange for the exchanging utilities?

Both the rate test and the DSI rate treatment after 1985 are parts of an overall package of measures developed in the Act. As part of the bargain BPA's customers, other than preference customers, accepted the risk of a "triggering" of the rate test should the Regional Act turn out to be less beneficial than anticipated. Investor-owned utilities purchasing for the residential exchange acknowledged and accepted the risk that excess costs caused by a triggering of the rate test could raise the cost of the exchange. Thus the cost of the residential exchange energy is increased when the rate test triggers as are the other categories of energy purchased under §7(b)(3).

Under §7(c)(1)(B), the DSI rate after 1985 is set "to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial customers in the region." But the DSIs themselves will pay for part of the cost shortfall that results from their own rate limitation under §7(c)(1)(B). This result occurs because the DSI rate under §7(c)(1)(B) is tied to the retail rates charged by BPA's preference customers. Any DSI cost shortfall caused by this section is spread back to the priority firm rate paid by preference customers and exchanging utilities. This result reduces the value of the exchange, but is also a risk accepted by the investor-owned utilities.

4. What control over BPA's budget and expenditures is available to BPA's customers?

BPA's customers have several avenues of control over BPA budgets and expenditures. The rate-setting process under §7(i) provides the customers ample opportunity to comment on revenue requirements for the applicable rate period. The congressional budget review process gives customers an opportunity to testify on every Bonneville budget. Bonneville's formal policy development process gives customers the right to review and comment on proposals that affect rates for several years in the future. Bonneville also consults informally and frequently with its customers groups on major issues that will affect future rates.

Of these methods, the Bonneville rate proceeding provides the fullest opportunity to control Bonneville's expenditures. Unlike Bonneville's budget submittals to Congress, revenue and expense information for each rate proceeding is current and not under OMB release restrictions. That information is subject to discovery and BPA's witnesses may be cross-examined.

The lack of timely information in BPA's budget submittals is caused by the Office of Management and Budget's requirement that BPA submit its budget by August each year, 14 months in advance of the relevant fiscal year. BPA actually prepares the budget several months in advance of the August submittal. OMB also prohibits BPA's sharing of this budget information until the following January, when the President submits his budget. By the time BPA begins a rate proceeding, it must revise much of the information submitted through the budget process.

5. What suggestions do the Northwest publicly-owned utilities have for improving BPA's repayment performance?

Bonneville's poor performance in repaying its federal debt obligations in recent years has been a result of overestimates of revenues, caused by overestimates of loads and underestimates of costs. The underestimates of costs were due primarily to WPPSS cost overruns. BPA has been unable to timely reflect those costs in rates. Northwest preference customers have been working closely with Bonneville to improve its repayment performance. In our judgment, the major problems have been corrected. Preference customers believe little change is now needed to ensure Bonneville's repayment performance.

The most important factor in improving BPA's repayment performance is BPA's ability to change its rates more frequently to reflect changes in loads and costs. The inability to raise rates between 1974 and 1979 and between 1979 and 1981 effectively prevented Bonneville from meeting its repayment schedule.

The second factor is an improvement in the accuracy of the load forecasts for BPA's customers. Revenues are directly related to loads, so that poor load forecasts will produce poor revenue forecasts. In previous rate periods DSI and nongenerating utility customer load forecasts were particularly off the mark. BPA has adopted a new forecasting model for nongenerating utility loads that is far superior to BPA's previous model. BPA also has stopped using DSI operating demands as the load forecast for the DSIs, and has developed an independent DSI load forecasting model. These changes represent the major improvement in BPA's revenue forecasting capability.

BPA's load forecasting performance this past year should not be considered a reflection on BPA's overall ability to project loads. A combination of unusual circumstances led to significant load underruns. No one, for example, could have projected that last winter would be one of the warmest in history. No one could have projected that the California intertie would be loaded with California hydroelectric energy from Northern California dams, thus delaying Northwest surplus sales and causing generating preference customers to displace some of their BPA purchases with nonfirm energy normally sold elsewhere. No one could have projected the severity of the recession that led to an especially sharp dip in the Northwest economy. No one could have projected the effect that the new federal PIK program would have in reducing irrigation loads. Finally, neither BPA nor the aluminum industry nor any of the major forecasting services projected the collapse of aluminum prices last year that led to the shutdown of Northwest potlines.

The third factor which will improve BPA's repayment performance is better cost projecting. Because of more frequent rate adjustment proceedings, BPA's short term cost projections have come under close scrutiny by its customers. Under this scrutiny, we believe BPA has so improved its cost projecting ability so that major cost deviations should be kept to a minimum.

Finally, PPC has supported Bonneville's rate adjustment clauses in the 1983-85 rate proposal that are designed to protect the agency from sharp changes in its more volatile cost components: the Residential Exchange and the WPPSS budgets. PPC has also endorsed BPA's intention to speed up amortization payments to the Treasury, even though those deferral adjustments raised BPA's overall revenue requirements by $75 million a year.

6. What is the position of the Northwest publicly-owned utilities on H.R. 3177, the proposed BPA Fair Ratemaking Act of 1983?

The Public Power Council strongly supports H.R. 3177 with some modifications. PPC and other BPA customer groups have long sought an independent hearing officer who would submit findings of fact and conclusions of law to the administrator for the administrator's final decision. We applaud this effort by our Northwest Congressmen.

The modifications which PPC has suggested, and which appear to be acceptable to the bill's sponsors, are: (1) inclusion of a saving provision which would exempt from the new law any past or present BPA rate proceeding; (2) provision for the appointment of the hearing officer from a neutral panel; and (3) provision that the hearing officer make rate recommendations to the administrator. The administrator would be required to take action within 60 days to either approve the recommendations of the hearing officer or to change those recommendations, giving the administrator's reasons based on the record. This change would retain responsibility for the rates with the administrator. As presently written, H.R. 3177 would allow the administrator to step back and accept no responsibility for the rates.

7. Would the Northwest publicly-owned utilities favor a proposal requiring BPA to submit rate adjustments to FERC for confirmation and approval 6 months prior to the proposed effective date, if FERC were (1) required to complete its review (both under Regional Act §7(a)(2) and §7(k)), based on the record in BPA's proceeding, within the 6-month period, and (2) empowered to order all BPA rates increased by a uniform percentage to cover any perceived prospective revenue shortfalls?

First, PPC does not believe that requiring BPA to submit its proposed rates to FERC six months ahead of the effective date would improve the process or the rates themselves. BPA must make many projections to fix rates for the future; these projections are constantly updated with new information as the rate hearings proceed. If BPA were forced to have the proceedings concluded several months earlier, the projections that BPA sent off to FERC for approval would be less accurate.

Second, given the size and complexity of the rate hearings, BPA cannot move through them much faster than it does now. (The 1983 proceeding took about seven-months.) Imposing an earlier deadline would simply require an earlier starting date for the hearings. If BPA were to adjust its rates each year as permitted in its power sales contracts, the six-month filing requirement would force BPA to start a new proceeding before its last rate adjustment had gone into effect. Thus BPA could be simultaneously holding hearings on the next adjustment while appearing before FERC to support the previous, but still proposed and pending, rate adjustment.

The Public Power Council believes that putting fixed time limits on FERC review is a good idea. However, Congress must consider FERC's staffing and budget limitations. FERC already has a difficult burden in reviewing BPA rates, partly because of FERC's limited staff and budget.

Finally, it must be remembered that the scope of FERC's authority to review BPA rates is still under consideration by the United States Court of Appeals for the Ninth Circuit. The decision by the Ninth Circuit will affect the depth of FERC's review and the breadth of FERC's remedies. Congress should be wary of imposing time limits and remedies on FERC before we have the Ninth Circuit's interpretation of existing law.

8. Do the Northwest publicly-owned utilities intend to sign BPA's long term conservation contracts as presently offered? Which elements of these contracts require improvement?

The Public Power Council does not submit an answer to this question. The PPC understands that individual utilities will submit answers.

9. Do the Northwest publicly-owned utilities favor a "mitigation by exclusion" approach to maintenance of indoor air quality in residential weatherization programs?

The Public Power Council does not submit an answer to this question. The PPC understands that individual utilities will submit answers.

TESTIMONY OF
R. KEN DYAR
on behalf of
CENTRAL LINCOLN PEOPLES UTILITY DISTRICT
and
THE PUBLIC GENERATING POOL

Good morning, Mr. Chairman:

My name is R. Ken Dyar. I am the manager of Special Projects for Central Lincoln Peoples Utility District. I am testifying on behalf of the District and the Public Generating Pool.

The District is a publicly-owned utility serving approximately 25,000 customers in four Oregon counties along the central coast. The District has priority access to federal power and purchases virtually all of its wholesale power and energy from the Bonneville Power Administration. In 1982, the District purchased 1.2 billion kilowatt-hours and paid about $15.5 million to Bonneville.

The Public Generating Pool is an unincorporated association of publicly-owned utilities. The following members of the Pool submit this testimony: the Cities of Seattle and Eugene, and the Public Utility Districts of Cowlitz, Chelan, Douglas and Grant counties of Washington.

These utilities own and operate electric power generating resources and are priority customers of Bonneville. In 1982, the PGP members purchased approximately ten billion kilowatt-hours from BPA and paid more than $105 million to BPA.

I am here to address issues arising out of the 1983 Bonneville rate case, which are of special interest to these utilities, as well as the implications which these issues have for Bonneville's rate program in subsequent years. The problems which I will discuss arise because Bonneville is asserting absolute discretion in setting these rates, ignoring the contractual and statutory limits set by Congress. As a result, Bonneville violates the statutorily mandated priority to federal power to publicly-owned utilities, thereby creating subsidies to other customer classes.

We support Bonneville in its desire to place itself on a sound financial basis and collect revenues sufficient to meet its financial obligations. This was the thrust of our testimony in the 1983 rate case. We believe a financially healthy Bonneville is crucial to the health of our utilities. Nevertheless, it is clear this financial health can only be pursued and implemented within the bounds set by Congress. The longest-standing constraint on the Administrator's discretion is the priority access to supply and price accorded publicly-owned utilities in the marketing of federal power. The Administrator, in this rate case, has sought to extract additional revenues from the priority customers through a variety of devices, while at the same time manipulating cost allocations, loads and resources, and rate designs to hold down the rates of other customer classes. The Administrator simply is not free to balance his budget on our backs.

In the 1983 rate case, the Administrator went beyond the statutory bounds placed upon his discretion when he decided to artificially reduce the size of the "federal base system resources" (FBS) to the detriment of the publicly-owned utilities. The federal base system resources are defined by the Pacific Northwest Electric Power Planning and Conservation Act (Public Law 96-501) and the Power Sales Contracts into which the Administrator has entered with the publicly-owned utilities. The FBS resources, generally speaking, are the least expensive resources in the region. P.L. 96-501 clearly states that the requirements of the publicly-owned utilities are to be served first with federal base system resources to the extent FBS resources are available. Only if those resources are insufficient are the publicly-owned utilities to be served with other, more expensive resources. These other resources include "Exchange Resources" and "New Resources."

The "Exchange" is a paper transaction authorized by P.L. 96-501, wherein private utilities and some public utilities exchange a portion of their more expensive power for cheaper BPA power. The gross cost of this Exchange exceeds $1 billion. The "New Resources" pool consists of approximately 20 MW's of precontracted power. Due to the surplus, the region has little need for the new resources pool.

What is at issue here is preference and priority access to the FBS. Apparently, due to the region's surplus, the Administrator decided to "adjust" the size of the FBS. Such manipulation caused a nominal decrease in the capability of the FBS, which in turn increased the priority access customers' dependence on the Exchange resources. (See Appendix.) BPA reduced the size of the FBS through several means.

First, BPA asserted discretion in calculating the capability of the federal hydro system Without bogging down in technical detail, I would just note that BPA simply assumed less firm energy would be available from the federal hydro resources, when clearly the physical capability has not changed.

Second, Bonneville implemented a fish and wildlife program, which increases the water release on the Columbia River during the month of May each year. According to Bonneville, such a release results in unmarketable firm energy, since the hydro system either has to generate substantially more energy in May than is necessary to meet firm loads, or to spill water. In response, Bonneville chose to calculate the firm energy capability of the federal hydro system by totally excluding the firm capability of May, pretending that no firm power at all is generated by the system during that month. This artificial assumption reduced the capability of the FBS by approximately 400 MW (and correspondingly increased the amount of the Exchange costs assigned to the priority access customers).

Third, Bonneville reduced the FBS capability even further by eliminating half of the output of the Hanford Generating Project from the FBS, even though the preference agencies' long-term power sales contracts and P.L. 96-501 require inclusion of the full capability of the project as an FBS resource. This BPA action costs the priority access customers another 240 MW of firm power.

By artificially understating the size of the federal base system, Bonneville prematurely forces more expensive resources on to the publicly-owned utilities. This violation of preference and priority forces these utilities to pay about 4 mills per kilowatt-hour (out of a total of 22 mills/kwh), or about $320 million.

What I have described is a violation of preference and priority which resulted from the Administrator's decisions in the 1983 BPA rate case. A concommitant problem arising from the same decisions is abuse of the discretion which Congress has vested in the Administrator.

First, and foremost among these for the PGP, is the Administrator's imposition of a so-called "availability charge" on the generating public utilities. In the 1960's and 1970's, Bonneville encouraged these utilities to build resources to meet some of their own loads. They did so. Bonneville has employed rate structures which encourage these utilities to dedicate these resources to serve loads rather than selling the power to others and permitting Bonneville to market its resources to others.

Now, Bonneville finds itself with surplus power. In this rate case, BPA adopted a new penalty -- the availability charge -- which we believe violates the new power sales contract provisions. More importantly, for this Subcommittee, Mr. Chairman, is the fact that this is a prime example of Bonneville arbitrarily abandoning a previous long-standing policy and forcing its customers on a totally different direction.

Furthermore, Bonneville assigns costs on expected loads. The Exchange costs, assigned to the industrial customers, have caused reallocation of costs over the last two years which have been quantified. Due to the melding of firm and non-firm prices in designing the industrial rates, the underrun loads of these customers have cost Bonneville's other customer classes $92 million in 1982, and, according to our best estimations, $60 million in

1983. These examples clearly illustrate Bonneville's refusal to recognize Sections 7(c)(1)(a) and 7(b)(3) of P.L. 96-501. The first provision requires the industrial customers to absorb the cost of resources projected to be needed to serve such load as well as the net costs of the exchange prior to July 1985. Section 7(b)(3) is a safety net to ensure that over- or under-recovered costs resulting from fluctuating industrial loads and the Exchange will not be charged to priority customers.

Finally, Mr. Chairman, we believe the Subcommittee should share our concerns with preference and priority to federal power and the Administrator's discretionary actions that attacks the pricing of federal power -- now and in the future.

You are aware that the direct service industry rates after 1984-85 are correlated to a loose set of standard of publicly-owned utility rates to similar industrial customers. However, the DSI rates cannot be below the rates set by Bonneville in 1984-85.

The Administrator's policy decisions in the 1983 rate case indicate that he intends to establish a low rate floor for these other customer classes now and argue with us over the loose standards of post 1984-85 later. We believe P.L. 96-501, along with its history, numerous statements and testimony to Congress are absolutely clear that all power sales under the statute are subject to the Bonneville Project Act.

> "Section 5(a) makes clear that all power sales under this bill are subject at all times to the Bonneville Project Act, particularly sections 4 and 5 of that Act. This provision therefore retains the preference and priority accorded public bodies and cooperatives in BPA power sales Related preference protecting provisions include 5(b), 7(b) and 10(c)." [Emphasis added.]

Throughout the long debate over P.L. 96-501, preference and priority for the publicly-owned utilities was never a serious national policy issue with the Congress. Yet, as recently as October 12, 1983, Bonneville staff have questioned whether Congress really intended to maintain preference and priority to the publicly-owned utilities.

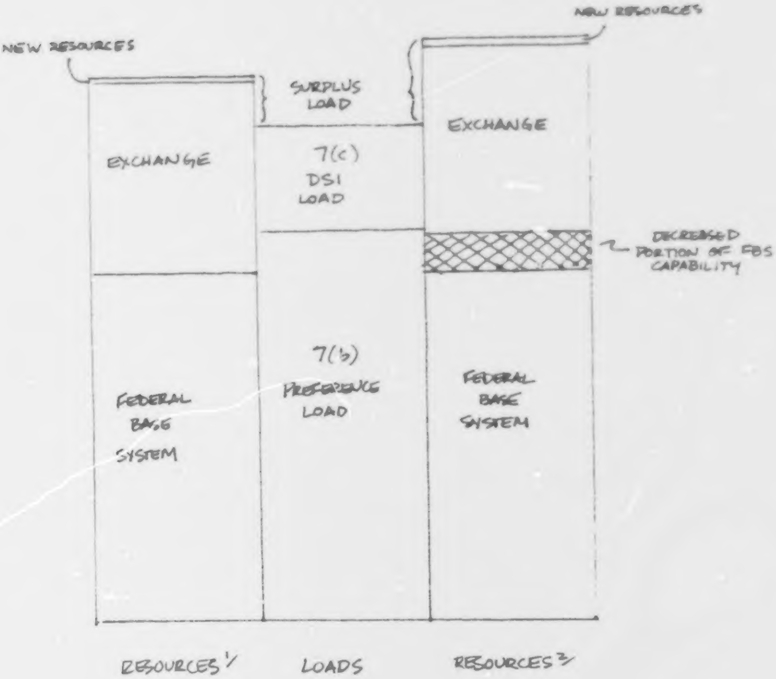
Under P.L. 96-501, Bonneville was obligated to develop a methodology/program for implementing the 7(b)(2) rate test by November 1983. Due to the time demands of the 1983 rate case, the customers of Bonneville agreed to extend the completion date for such a methodology to March 1984. The rate test is the cornerstone of P.L. 96-501 for the priority customers of Bonneville.

Bonneville has begun interpretative rule making on Sec. 7(b)(2) of P.L. 96-501, which carries out the congressional mandate of priority access to the lowest cost federal power.

In a letter dated October 12, 1983, Bonneville suggests that there is a heirarchy of statutory duties, and protection of priority to price is not very high on Bonneville's list. Secondly, the letter states that the rate ceiling (Sec. 7(b)(2)) operates only in a power deficit situation.

Again, we are seeing the assertion of absolute discretion by the Administrator. The rate directives in Section 7 protect all classes of customers, and must be carried out according to the statutory requirements. Bonneville cannot "interpret" away rights granted by federal law.

IMPACT ON PREFERENCE CUSTOMERS OF THE 1983 RATE CASE


NEW RESOURCES
EXCHANGE
FEDERAL BASE SYSTEM
SURPLUS LOAD
7(c) DSI LOAD
7(b) PREFERENCE LOAD
NEW RESOURCES
EXCHANGE
DECREASED PORTION OF FBS CAPABILITY
FEDERAL BASE SYSTEM
RESOURCES 1/
LOADS
RESOURCES 2/

1/ RESOURCES AS IDENTIFIED BY THE ADMINISTRATOR

2/ RESOURCES AS IDENTIFIED BY THE PUBLIC GENERATING UTILITIES

Testimony of Richard L. Bidwell,
Reynolds Metals Company
before the
Subcommittee on Mining, Forest Management & BPA
House Committee on Interior and Insular Affairs
October 27, 1983

Panel I: BPA Revenues and Repayment

Good morning. I am Richard L. Bidwell, Director of Energy Resources for Reynolds Metals Company. Reynolds operates two primary aluminum smelters in the Pacific Northwest, at Longview, Washington and Troutdale, Oregon which together employ about 2000 people. My present office is in Portland, Oregon.

Reynolds is a direct service industrial customer (DSI) of the Bonneville Power Administration. Although the short time available has made it impossible for the other DSIs formally to review and adopt this testimony, I believe they generally share the views and concerns expressed here.

Description of the DSIs

The DSIs are a group of 15 industrial firms operating 20 plants in the Pacific Northwest which purchase electric power directly from BPA rather than from local utilities. The DSI companies produce approximately one-third of the nation's primary aluminum, 100% of the nation's domestically mined nickel, other metals and fabricated goods, chemicals and other important products. At full operations the DSIs employ about 15,000 people with a payroll of over $500 million a year. In total, the DSIs contribute over $1.5 billion a year to the Northwest economy. In Oregon alone, we employ over 2,300 people with an annual payroll of about $75 million, and provide some $8.5 million a year in state and local taxes. The DSIs obviously are important to the national interest as well, because of the need for aluminum in national defense, and the contribution of this production to America's balance of trade.

The DSIs are also an important part of the Northwest's power system. BPA estimates that under its new rates the DSIs will purchase about 17.7% of its firm power and pay approximately 22% of its revenues. In contrast, BPA estimates that its preference utility and residential exchange customers will purchase about 72.3% of BPA's power but pay only 56.4% of its revenues. [Much of the higher rates paid by the DSIs go to subsidize the residential and small farm exchange program established under the Regional Power Act. The 2.1 million Northwest residential and small farm ratepayers of the region's investor-owned utilities participating in the exchange received over $216 million in total rate relief in fiscal year 1982, paid for primarily by the DSIs.]

In addition to paying a substantial share of BPA's revenues, the DSIs also provide BPA with valuable power system reserves.

BPA's broad rights to interrupt DSI loads protect other customers during shortages and emergencies while avoiding the need to build and maintain expensive standby power plants. Unlike other customers who receive firm service for 100% of their load, BPA serves one-quarter of the DSI load with a combination of nonfirm power and power provided on a contingent basis. This benefits all power consumers by avoiding the need to develop additional power plants and by making more efficient use of the Columbia River power system.

DSI Rate Concerns

The DSIs obviously are a valuable part of the region's power system and economy and important to the nation as a whole. The ability of the DSIs to continue to provide these benefits, however, has been seriously threatened by higher, noncompetitive power rates. The DSIs expected rates to go up substantially as a result of higher costs and the residential exchange program established by the Regional Act, but the increase has been much higher and steeper than anyone expected. DSI rates have climbed 800% since 1979, from 3.17 mills per kilowatt-hour to 26.8 mills. While a "mill" is only 1/10 of one cent, each one mill increase in the DSI rate raises total DSI power costs by over $30 million per year at full production. These tremendous rate increases threaten to price the Northwest aluminum industry out of the international marketplace.

I realize that people from other parts of the country sometimes find it difficult to be sympathetic with electricity rates in the Pacific Northwest. After all, residential rates in the Northwest are less than half the average rate paid by consumers in other parts of the country. However, BPA's rate to the Northwest aluminum industry (26.8 mills/kwh) is more than 50% higher than the average cost of power last year to all smelters operating in the free world (17 mills) and substantially higher than the average cost of power to total free world smelting capacity (22 mills). In an independent study commissioned earlier this year by the DSIs, Battelle Pacific Northwest Laboratories estimated that 83% of all operating smelting capacity in the world had lower power costs than the Northwest aluminum industry.

Since electricity represents as much as one-third of the cost of producing aluminum, power rates basically determine the competitive viability of aluminum smelters. And because BPA's rates have increased so much above the average cost of power to other smelters, some Northwest plants have become "swing" plants that operate when the economy is strong, but are among the first plants shut down during soft markets and among the last plants returned to full production when markets improve. BPA's recent experience confirms this. Prior to the recent rate increases, the DSIs had never made substantial load reductions during significant market downturns. Last year, after the higher rates were imposed, the Northwest aluminum industry was forced to curtail production to about 55% of capacity while plants in other parts of the world with lower power rates continued to operate at full production. When BPA offered the industry lower-cost surplus power last spring, production in the Northwest increased dramatically. With a more competitive rate, the DSIs have been able to bring over 1,600 people back to work and increase BPA's revenues by more than $25 million. Now that the economy is improving, virtually all operations in the Northwest are returning to full production.

BPA projected in designing its new rates that the economic recovery would continue and that the DSIs would be able to operate even at BPA's higher charge for power. We in the aluminum industry certainly hope that BPA's economic forecast is right. But regardless of the short-term, the DSIs have a fundamental long-term problem. While we can operate profitably during the economic "peaks," no industry can long survive the cyclical "valleys" of the marketplace. This is especially true when struggling under the competitive disadvantages of higher-than-average basic production and shipping costs. To make the necessary capital improvements to our plants, BPA must develop competitive, predictable rates for the DSIs.

Although the DSIs' problems are serious, I still am hopeful that they can and will be resolved. The DSIs do not request or expect a subsidy to remain competitive. To the contrary, DSI rates are substantially higher than the actual cost of serving the DSIs in order to subsidize other customers in intended--and unintended--ways.

DSI rates are high in part because regional power costs to all customers have increased much more than expected. Although painful to all customers, these added costs are a fact of life. And DSI rates were supposed to go up significantly under the Regional Act to help provide wholesale rate parity to the residential customers of the region's private utilities. These increases were also expected. However, in addition to these anticipated increases, the way the exchange and BPA rates have been administered has shifted some costs disproportionately to the DSIs. These extra charges are improper and unfair and make the marginal difference in competitive viability of the DSIs. If BPA corrects these problems, the DSIs can continue operating over the long-term and providing substantial benefits to the power system and economy in the Northwest and nation.

BPA Revenues and Repayment

I have focused on DSI rate concerns because our problems are crucial to the topic of this panel--BPA revenues and repayments. Although I am not an expert in BPA's budget or ratemaking, I am told by our experts that BPA's revenues should be adequate to cover its total costs and to catch up on past revenue shortfalls, under normal conditions.

However, the disproportionate rate treatment accorded the DSIs involves high risk for BPA. By raising the DSI rate to a level that is significantly above the cost of serving our facilities and is not competitive with plants in other areas, BPA is gambling that international markets for our products will remain strong and the DSIs will continue to be able to operate. If the economy weakens significantly and DSI loads decline, BPA may not be able to cover its operating costs and debt service to the U.S. Treasury. BPA might have avoided this risk by establishing cost-based DSI rates at a competitive level.

BPA is trying to hedge its gamble by imposing a penalty through a "customer charge" if the DSIs cannot operate at these high power costs. We are convinced that this so-called "customer charge" violates both the letter and the spirit of BPA's contract with the DSIs, which allows for curtailments under certain mutually agreed conditions and payments. We also are convinced that the customer charge is poor policy and could backfire to the detriment of BPA, the region and the nation. If BPA's industrial rate is competitive, our plants will continue to operate; if not, the plants ultimately will be in jeopardy. In this event, BPA's revenues will be significantly reduced. BPA already faces over $60 million in costs from surplus power it projects cannot be sold at cost. The region simply cannot afford the risk of losing substantial load, or the benefits the DSIs provide.

The DSIs support Peter Johnson's efforts to preserve BPA's fiscal integrity. In the past, BPA has failed to make its scheduled repayments to Treasury, but largely due to factors beyond BPA's control, such as periodic poor water conditions that reduce BPA's projected revenues or as WPPSS construction overruns which increase BPA's costs. BPA seems to have addressed these problems in the current rate case by taking measures to reduce its costs and by making relatively conservative assumptions about loads and resources. However, BPA has not adequately dealt with the greatest risk, which is entirely within its control: the competitiveness of the DSI rate. BPA must establish a fair, cost-based, competitive rate for its industrial customers if the agency is to meet its revenue needs and if the Northwest aluminum industry is to to continue providing significant benefits to the region and the nation.

TESTIMONY OF

RICHARD L. BIDWELL
Reynolds Metals Company

BEFORE THE SUBCOMMITTEE ON MINING, FOREST MANAGEMENT AND BPA
House Committee on Interior and Insular Affairs
October 27, 1983

PANEL II: BPA Ratemaking Procedures and Post-June, 1985 Rates

I am Richard L. Bidwell. I have previously identified myself in my testimony on Panel I.

Here, I wish to address the subject of BPA's ratemaking procedures and certain matters concerning post-June, 1985 rates. These are the topics assigned to Panel II. As before, my comments are made on behalf of Reynolds Metals Company and have not been formally approved by any of the other direct service industries. However, I believe the other companies generally share the concerns and views expressed here.

BPA'S Ratemaking Procedures

BPA has now conducted three rate proceedings since passage of the Regional Power Act on December 5, 1980. These hearings have been conducted in accordance with Section 7(i) of the Act and under a set of rules and procedures which BPA adopted for this purpose. These hearings represent a substantial departure from BPA's prior practice, when rates were established through consultation with various customer groups and after a notice and comment procedure which provided BPA's customers and other interested parties an opportunity to participate in the process.

BPA's three post-Act rate hearings have been prolonged and contentious affairs. The 1983 hearing lasted almost seven months, produced approximately 10,000 pages of recorded testimony, thousands of pages of prepared direct testimony and supporting exhibits, and tens of thousands of pages of discovery documents. The parties filed not one or even two, but three briefs in support of their respective positions, plus made oral argument to the BPA Administrator. In addition, the BPA staff held two rounds of "public hearings" throughout the Northwest, where members of the general public could address their concerns about BPA ratemaking.

I must tell you that the DSIs are not entirely happy with BPA's present rate procedures. One obvious reason for our concern is that we are disappointed with the results which have been reached. The hearings have not proved an effective way for us to communicate with BPA staff and other customer groups concerning the very real economic problems which confront the DSIs as a result of BPA's present rate levels, nor have the hearings proved an effective vehicle for discussion among BPA and its customers as to how best to achieve what should be in everyone's mutual interest: the most efficient, cost-effective power system possible.

But even if the DSIs were delighted with the results, it would still be true that BPA's rate hearings are too long, too complicated, too contentious, and too expensive. It makes no sense for BPA and its approximately 150 customers to be locked in serious combat for six months of each year, particularly when the next six months must be used for organizing and preparing for the next round of formal hearings. At some point, the sheer weight of the process hampers serious communication and mutual understanding.

Equally important, the fact that all issues are up for grabs each year, or at least appear to be so, introduces an element of uncertainty and unpredictability into BPA's economic relationships with its customers. No one doubts that BPA's costs are increasing and that BPA must adjust its rates from time to time to recover those costs. To the extent that the rate hearing is a forum to permit BPA's customers to test BPA's proposed expenditures, the hearing issues are relatively straightforward and the outcome is reasonably predictable, within a tolerable margin of error.

But most issues in BPA's rate hearings have little to do with expenditures. Instead, the issues generally focus on splitting BPA's costs among its several customer groups. Because there is no established or agreed upon procedure for cost allocation among customer classes, the annual hearing has become a battleground among proponents of various economic and accounting theories as to best allocation of these costs. Compounding the problem, there are no obvious, objectively correct solutions to the cost issues.

Many of these theoretical allocation methods depend upon projections of future events and/or costs. Thus another major area of dispute is competing views of the future.

BPA's reliance on theoretical ratemaking and predictions of future events and costs makes it very difficult for my company or any other BPA customer to anticipate the result of any rate case. This unpredictability severely impacts our ability to do sound planning for future capital expenditures.

As required, BPA's rates must be sufficient over time to cover all of its costs, including repayment of its obligations to the U. S. Treasury. At the same time, BPA must establish rates at the lowest possible cost to all of its customer groups and promote the widespread use of electrical energy. And these requirements must be accomplished in accordance with "sound business principles."

BPA's obligations to the Treasury, its customers, and to the general public require that it take all reasonable steps to reduce the present level of contention which surrounds its rates and the ratemaking process. Recent developments at BPA, including the designation of a deputy power manager with clear authority over the rate process, is an important step toward achieving this goal. Over the next several months, we hope that BPA management and staff will work closely with BPA's customer groups in an effort to avoid the discord which has surrounded previous rate hearings.

The goals of predictability and certainty can only be realized when BPA has forged an essential consensus among its customer groups. This requires hard work by both BPA and all of the customers. No legislation is required to accomplish this result, as BPA has ample authority under the existing statutes to meet this obligation. The attached letter of August 8 to Representatives Swift and Wyden outlines the DSIs' position on H.R. 3177.

Pst-July, 1985 Rates

The Committee also requested comments concerning the rate tests in Section 7 of the Regional Act and the "survival" of the Residential Exchange.

BPA's rates after July 1, 1985 contain an inherent tension: the exchange continues thereby increasing BPA's costs and providing substantial subsidies to the residential customers of the region's private utilities, but the rates to all of BPA's customers are based on the lowest cost §7(b) rate and no customer directly pays the additional costs the exchange imposes on BPA. Preference customers buy power at the §7(b) rate as limited by the rate ceiling. Exchange customers also buy power at the §7(b) rate plus a surcharge if the rate ceiling triggers. (But BPA cannot actually collect any revenue shortfalls from some exchange customers because the Exchange Agreement gives them the right to "deem" out of the exchange if their average system cost drops below the §7(b) rate.) DSI rates after 1985 essentially are equal to BPA's §7(b) rate to the public agencies, plus a typical markup, minus adjustments for the lower cost of serving loads of the size and character of the DSIs, and minus a credit for the value of reserves. When all these adjustments are made, the resulting DSI rate will be at or below the §7(b) rate. (The so-called "floor" in §7(c)(2), which provides that DSI rates after July, 1985, shall not be less than rates in the prior year, could produce real inequities by requiring the DSIs to pay more than the actual cost of service under the post-1985 rate directives.)

The topic of this panel indicates that the Committee is concerned whether these rates will allow BPA to cover its total costs--especially the additional costs of the exchange-- while protecting rates to preference customers as intended by the §7(b)(2) rate ceiling. This is a very real and legitimate concern. BPA's rates may not add up to its total costs at the current high level of exchange costs. Obviously something has to "give" since BPA must cover its costs.

The solution to this post-1985 rate dilemma is not to require preference customers, or any other BPA customer, to give up rate protections contemplated by the Regional Act. The solution is to ensure that the exchange, which causes the rate dilemma, includes only those costs contemplated by the Regional Act. The Act was intended to provide parity between public and private utilities in wholesale power costs by allowing private utilities to exchange power at their "average system cost of resources." However, the DSIs believe that the way in which average system cost currently is computed provides much more than the intended parity by allowing utilities to include costs in addition to resource costs.

BPA has taken steps to correct this problem by reviewing and revising the average system cost methodology. Failure to revise the methodology will jeopardize the rate protections to preference customers and BPA's other customers and the agency's own fiscal integrity. The DSIs are optimistic that the review process will lead to changes in the methodology that reduce average system cost to the intended level and ensure that all customers receive the rate benefits and protections contemplated by the Regional Act.

TESTIMONY OF

BERNARD V. PALK

SYSTEM DEVELOPMENT DIVISION

CITY OF LOS ANGELES DEPARTMENT OF WATER AND POWER

On Behalf of

THE CITY OF LOS ANGELES DEPARTMENT OF WATER AND POWER

THE PUBLIC SERVICE DEPARTMENT OF THE
CITY OF BURBANK

THE PUBLIC SERVICE DEPARTMENT OF THE
CITY OF GLENDALE

THE WATER AND POWER DEPARTMENT OF THE
CITY OF PASADENA

- Relating to the -

Oversight Hearings Before the

Subcommittee on Mining, Forest Management
and the Bonneville Power Administration

Jim Weaver, Chairman

U.S. HOUSE OF REPRESENTATIVES
Committee on Interior and Insular Affairs

Washington, D.C.

October 27, 1983

My name is Bernard V. Palk and I am from the City of Los Angeles Department of Water and Power where I am the Assistant Division Head of the System Development Division. This testimony is submitted on behalf of the City of Los Angeles Department of Water and Power (Los Angeles), the Public Service Department of the City of Burbank, the Public Service Department of the City of Glendale, and the Water and Power Department of the City of Pasadena (collectively referred to as Cities).

Our four utilities are interconnected adjacent municipal electric systems serving the greater Los Angeles metropolitan area of Southern California. Our utilities serve a population of approximately 3.5 million people and have a combined annual sales in excess of 20.5 billion kilowatt hours of energy. The service is rendered to approximately 1.4 million residential customers as well as 200,000 commercial and industrial customers. Our aggregate capacity is 7,532 megawatts, with a 1983 non-coincidental peak load of 5,084 megawatts.

I appreciate this opportunity to appear before you today and give you our perspective on some Bonneville Power Administration (BPA) ratemaking issues as well as on some related issues concerning transmission capacity and power transactions between the Pacific Southwest and the Pacific Northwest. In summary, the subjects I wish to discuss are:

1) BPA's discriminatory operating practices between the two regions and the attendant revenue losses to the PNW;
2) Problems observed in BPA's ratemaking and FERC's review processes;
3) Impediments and incentives to interactions between the Pacific Northwest and Pacific Southwest; and
4) Recommendations to rectify the problems related to the issues noted above.

Historical Background

It may be helpful to have a brief historical background of the interactions between the PNW and the PSW.

Nearly two decades ago, the major California utilities, among others, and BPA, along with other PNW utilities, agreed to develop and construct the two 500 kV AC and one 750 kV DC Intertie lines interconnecting the two regions. This decision was due in part to BPA's demonstration of historical (i.e., 50 years) availability of excess surplus energy, which had been initially valued at 2.0 mills/kWh, and the need for seasonal support to the PNW which could be provided by the PSW. This 2.0 mills/kWh charge for surplus energy appeared to be a reasonable recovery rate for a resource that would have been otherwise wasted by being spilled and lost to beneficial use. The availability of this surplus, which is sometimes referred to as dump energy, was one of the contributing factors to the economic justification of the intertie lines.

Since the operation of the 750 kV DC intertie, which was later upgraded to 800 kV DC, the Cities have been customers of BPA and other utilities in the PNW, purchasing both capacity and energy. We are currently in the process of a further Intertie upgrade from 800 kV to 1,000 kV. The result of these two upgrades is that we will increase the Intertie transfer capability from 1,440 MW to 2,000 MW. The Cities have a 50 percent ownership entitlement in the DC Intertie which, after the upgrade, represents 1,000 MW.

In calendar year 1982, Los Angeles alone purchased 3,361,087 mWh of energy from BPA and the other Northwest entities, providing approximately 33.3 millions of dollars for the Pacific Northwest economy.

Discriminatory Operating Practices

The sale of nonfirm energy makes a significant contribution (8.7 percent in O.Y. '85) to BPA's total revenue. The operating practices regarding nonfirm sales consequently have a substantial impact on these revenue recoveries.

We believe that BPA operates in a highly restrictive and discriminatory manner toward the PSW. This includes limiting its nonfirm sales and refusing to offer nonfirm energy, which has been declined in the PNW, to the utilities in the PSW. In our testimony during the 1983 rate hearings, we estimated that BPA's nonfirm operating practices cost Bonneville a potential revenue loss of over $114,000,000. Also, BPA's proposed 1983 nonfirm energy rate structure will perpetuate the discriminatory practices by, among other things, allowing the same type of energy to be sold to the same customer class at different prices.

If BPA would operate its system in a less restrictive and discriminatory manner, BPA could increase its revenue recovery while still observing the requirements mandated by law.

Problems Observed in BPA's Ratemaking and FERC's Review Processes

During our involvement in the 1983 and prior rate hearings, we have observed that BPA provided incomplete and inaccurate studies in support of its proposed rates; gave no opportunity for parties to make oral comments and cross-examine BPA staff on changes made following closing of oral presentations; and performed no cost-of-service study to identify the costs incurred in providing nonfirm service. Furthermore, FERC's review process, which may find BPA's rates to be inappropriate and which may have been placed into effect on an interim basis, does not remedy the problem by ordering either a rate adjustment or a refund to affected parties.

Impediments and Incentives to Interactions Between the PNW and PSW

Recent proposals to increase the intertie capacity between the PNW and PSW regions (i.e., between Celilo, Oregon and Mead, Nevada) could be impeded by the historic volatility of nonfirm rates, potential Intertie access charges, inconsistency in BPA's operating practices, uncertainty of nonfirm energy availability to the PSW due to expanded sales within the PNW, and short-term recall provisions of contracts entered into with the PSW. All of these factors must be taken into consideration when examining the economic justification of an intertie project.

Notwithstanding the above impediments, given the proper incentives, the Cities would like to continue to conduct business with, and thus contribute to the economy of the PNW. Realizing the anticipated abundance of available surplus energy, the seasonal and daily load diversity and the prospects of a truly cost-of-service based nonfirm energy rate structure, there are financial benefits that are available to both regions from continued and increased interactions.

Recommendations

In view of the preceding discussion, the Cities offer the following recommendations:

1. That BPA should re-evaluate its operating procedures concerning the timing and amount of nonfirm sales. In particular, a new study should be initiated of the Columbia River Basin, its various reservoirs, dams and electrical facilities, to determine the optimum manner of system operations;

2. Amend statutory requirements, such that once the availability of surplus energy has been declared by BPA, such surplus energy shall be offered first to the PNW and then shall be mandatorily offered to the PSW on the same terms as was offered to, but declined by, the PNW utilities;

3. As an alternative to No. 2 above, Bonneville should be required to request the Solicitor's Office of the Department of the Interior, or Congress should request the U.S. Attorney General's Office, to clarify that portion of the Regional Act (i.e., Public Law 88-552) concerning surplus energy as to when and by what terms it can or should be exported from the PNW region;

4. That FERC's final approval be obtained by BPA prior to implementation of any new rates, including interim rates;

5. That FERC should require BPA to establish rates based upon actual costs incurred to supply energy to each customer class; and

6. That BPA base its entire revenue requirement recovery on its firm energy sales and utilize any revenue realized from nonfirm sales to offset any deficits, or apply as a rebate adjustment to all of its customer classes after its Federal Treasury payment requirements have been met, or accelerate payments to the Treasury.

Conclusion

On behalf of the Cities of Los Angeles, Burbank, Glendale and Pasadena, I appreciate this opportunity to present our views and welcome the opportunity to answer any questions you may have. Thank you.

STATEMENT OF DANIEL C. LAMKE
OFFICE OF GENERAL COUNSEL
FEDERAL ENERGY REGULATORY COMMISSION
BEFORE THE SUBCOMMITTEE ON MINING, FOREST MANAGEMENT,
AND BONNEVILLE POWER ADMINISTRATION OF
THE COMMITTEE ON INTERIOR AND INSULAR AFFAIRS
HOUSE OF REPRESENTATIVES
OCTOBER 27, 1983

MR. CHAIRMAN AND MEMBERS OF THE SUBCOMMITTEE:

BY LETTER OF OCTOBER 12, 1983, FORMER CHAIRMAN C.M. BUTLER III OF THE FEDERAL ENERGY REGULATORY COMMISSION OR HIS DESIGNEE WAS INVITED TO TESTIFY BEFORE THE SUBCOMMITTEE ON MINING, FOREST MANAGEMENT, AND BONNEVILLE POWER ADMINISTRATION.

FORMER CHAIRMAN BUTLER HAS LEFT THE FEDERAL ENERGY REGULATORY COMMISSION AND ACTING CHAIRMAN ANTHONY G. SOUSA HAS DESIGNATED ME TO APPEAR BEFORE YOU AS A TECHNICAL STAFF WITNESS DURING THIS PERIOD OF TRANSITION. I SHOULD EMPHASIZE THAT MY REMARKS REPRESENT MY OWN PROFESSIONAL JUDGEMENT AND ARE NOT INTENDED TO CHARACTERIZE THE VIEWS OF INDIVIDUAL MEMBERS OF THE COMMISSION.

THE SUBCOMMITTEE'S INVITATION REQUESTED TESTIMONY WITH REGARD TO (1) THE STATUS OF BONNEVILLE POWER ADMINISTRATION REPAYMENT TO THE U.S. TREASURY, AND (2) THE PROPER ROLE FOR FERC IN REVIEWING, CONFIRMING AND APPROVING BPA RATE ADJUSTMENTS. IN ADDITION, COMMENTS WERE REQUESTED ON A PROPOSAL THAT BPA SUBMIT RATE ADJUSTMENTS TO FERC FOR CONFIRMATION AND APPROVAL SIX MONTHS PRIOR TO THEIR PROPOSED DATE DURING WHICH TIME FERC WOULD BE REQUIRED TO COMPLETE ITS

REVIEW BASED ON THE RECORD IN THE BPA PROCEEDINGS, FERC WOULD THEN FURTHER BE EMPOWERED TO ORDER ALL BPA RATES INCREASED BY A UNIFORM PERCENTAGE TO COVER ANY PERCEIVED PROSPECTIVE REVENUE SHORTFALLS. SUBCOMMITTEE'S LETTER OF INVITATION, ALSO INVITED COMMENTS ON H.R. 3177, THE BONNEVILLE POWER ADMINISTRATION FAIR RATEMAKING ACT OF 1983. THE PROPOSED BILL WOULD (1) FORBID ANY "INTERESTED PERSON," INCLUDING THE ADMINISTRATOR OR HIS STAFF, "FROM ENGAGING IN EX PARTE CONTACTS ON THE MERITS WITH THE HEARING OFFICER IN THE BPA PROCEEDING, (2) REQUIRE THE HEARING OFFICER TO PUBLISH AN INITIAL DECISION ON THE RATES TO BE ESTABLISHED," (3) PERMIT THE PARTIES TO FILE EXCEPTIONS TO THE HEARING OFFICER'S INITIAL DECISION, AND (4) AUTHORIZE THE ADMINISTRATOR TO ESTABLISH RATES DIFFERENT FROM THOSE IN THE HEARING OFFICER'S DECISION ONLY UPON "FULL AND COMPLETE JUSTIFICATION OF THE DIFFERENCES WITHIN 60 DAYS OF PUBLICATION OF THE INITIAL DECISION.

THE FERC'S MOST CURRENT STATEMENT WITH REGARD TO THE STATUS OF BPA REPAYMENT TO THE U.S. TREASURY IS FOUND IN ITS ORDER CONFIRMING AND APPROVING THE BONNEVILLE POWER ADMINISTRATION'S RATES ON A FINAL BASIS IN DOCKET NOS. EF81-2011, EF81-2021, AND EF82-2011.

IN ITS ORDER, THE COMMISSION NOTED, THAT BPA'S FILING IN DOCKET EF82-2011 INDICATED A FEDERAL INVESTMENT TO BE REPAID BY THE END OF FISCAL YEAR 1981 OF $4,191,749,000 IN GENERATION

FACILITIES AND $2,349,298,000 IN TRANSMISSION FACILITIES. THE FILING INDICATED THAT BPA HAS REPAYED APPROXIMATELY 10.5 PERCENT OF ITS GENERATION INVESTMENT AND 9.5 PERCENT OF ITS TRANSMISSION PLANT. THE COMMISSION THEN WENT ON TO NOTE THAT UTILIZING A COMPOUND OR STRAIGHT LINE AMORTIZATION METHOD, THE RANGE OF REPAYMENT FOR THE GENERATION INVESTMENT SHOULD HAVE BEEN FROM 18 TO 27 PERCENT OF TOTAL INVESTMENT AND FOR TRANSMISSION INVESTMENT, FROM 30 TO 39 PERCENT. THEREFORE, BPA'S REPAYMENT OF ITS GENERATION AND TRANSMISSION INVESTMENT, APPEARS TO BE MORE THAN $780,000,000 BELOW THE PAYMENT LEVEL REQUIRED USING THE COMPOUND AMORTIZATION METHOD AND $1.4 BILLION BELOW THE REPAYMENT LEVEL REQUIRED BY USING A STRAIGHT LINE AMORTIZATION METHOD.

FERC'S ROLE IN REVIEWING, CONFIRMING AND APPROVING BPA RATE ADJUSTMENTS IS SET FORTH IN THE 1980 PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT (16 U.S.C. 839e) PURSUANT TO WHICH THE COMMISSION IS OBLIGATED TO MAKE THREE SPECIFIC FINDINGS: THAT THE RATES:

(A) ARE SUFFICIENT TO ASSURE REPAYMENT OF THE FEDERAL INVESTMENT IN THE FEDERAL COLUMBIA RIVER POWER SYSTEM OVER A REASONABLE NUMBER OF YEARS AFTER FIRST MEETING THE ADMINISTRATOR'S OTHER COSTS,

(B) ARE BASED UPON THE ADMINISTRATOR'S TOTAL SYSTEM COSTS, AND

(C) INSOFAR AS TRANSMISSION RATES ARE CONCERNED, EQUITABLY ALLOCATE THE COSTS OF THE FEDERAL TRANSMISSION SYSTEM BETWEEN FEDERAL AND NON-FEDERAL POWER UTILIZING SUCH SYSTEM.

THESE REQUIREMENTS ARE SET FORTH IN SECTION 7(a) OF THE 1980 ACT. SUBSECTION 7(k) OF THE ACT FURTHER SPECIFIES THAT THE COMMISSION CAN APPROVE RATES FOR THE SALE OF POWER OUTSIDE THE REGION ONLY AFTER REVIEWING THE RATES FOR CONFORMANCE WITH CERTAIN OTHER ACTS AND AFTER OPPORTUNITY FOR HEARING.

UNDER THE 1980 ACT, HOWEVER, THE FERC DOES NOT HAVE THE AUTHORITY TO MODIFY FEDERAL RATES. AS A RESULT, THE COMMISSION'S REMEDIAL POWERS ARE LIMITED TO CONFIRMING AND APPROVING OR DISAPPROVING THE RATE. GIVEN THIS LIMITED AUTHORITY, IF BONNEVILLE'S RATES ARE INSUFFICIENT TO ASSURE REPAYMENT TO THE FEDERAL TREASURY, THE COMMISSION'S AUTHORITY IS CONFINED TO REJECTING THE RATES AND ORDERING SUBSTITUTE RATES TO BE FILED. PENDING SUBMITTAL AND APPROVAL OF SUBSTITUTE RATES, THE REJECTED, DEFICIENT RATES REMAIN IN EFFECT. IF BONNEVILLE FAILS TO FILE SUBSTITUTE RATES WITHIN THE PRESCRIBED TIME OR IF THE SUBSTITUTE RATES ALSO FAIL TO CONFORM TO THE STATUTORY STANDARDS, THE DEFICIENT RATES WILL CONTINUE TO REMAIN IN EFFECT UNTIL A HIGHER SUBSTITUTE RATE IS FILED BY BONNEVILLE AND CONFIRMED AND APPROVED BY THE COMMISSION.

WHILE RECOGNIZING SHORTFALLS IN BPA'S RATE FILINGS, I BELIEVE THAT ADDITIONAL COMMISSION REVIEW AUTHORITY IS UNNECESSARY SINCE ADEQUATE AUTHORITY NOW EXISTS IN THE DEPARTMENT OF ENERGY TO REQUIRE BONNEVILLE POWER ADMINISTRATION TO ADDRESS THE CAUSES OF ITS RATE FILING SHORTFALLS THROUGH THE RATE ESTABLISHMENT PROCEDURE.

DOE HAS SUFFICIENT AUTHORITY TO SCRUTINIZE AND MODIFY BPA'S REPAYMENT PRACTICES IF AND WHEN NECESSARY. THIS COULD BE ACCOMPLISHED THROUGH FINANCIAL REPORTING REQUIREMENTS TO DOE'S ASSISTANT SECRETARY OF ENERGY FOR CONSERVATION AND RENEWABLE ENERGY WHO IS RESPONSIBLE FOR ESTABLISHING THE PRIORITY OF BPA'S REVENUE APPLICATION TO THE FEDERAL INVESTMENT AND FOR ESTABLISHING BPA'S ACCOUNTING METHODS.

ANY SUCH ADDITIONAL SCRUTINY BY DOE OR OTHERS WOULD ASLO HAVE TO INCLUDE A REVIEW OF BPA'S FUTURE LOAD FORECAST TO ASSURE THAT THEY REFLECT BPA'S OPERATIONAL REALITIES AT THE TIME THAT THE BPA SETS ITS RATES. BPA HAS HISTORICALLY DEVELOPED OVERLY OPTIMISTIC SALES PROJECTIONS THAT ARE NOT BORNE OUT IN PRACTICE. SIGNIFICANT DEVIATIONS BETWEEN BPA'S FORECASTED SALES AND ACTUAL SALES HAVE GREATLY CONTRIBUTED TO THE INABILITY OF BONNEVILLE TO MAKE A QUICK PAYMENT FOR THE AMORTIZATION OF THE UNITED STATES' INVESTMENT IN THE FEDERAL COLUMBIA RIVER PROJECT SYSTEM.

THE DEPARTMENT OF THE TREASURY COULD ALSO ADDRESS THE QUESTION OF FEDERAL COST RECOVERY BY IMPOSING STRICKER CONTROLS ON BPA'S PROJECTED REPAYMENT SCHEDULE.

IN THE EVENT THAT BONNEVILLE AND THE ASSISTANT SECRETARY OF ENERGY FOR CONSERVATION AND RENEWABLE ENERGY ADDRESS THE UNDERLYING CAUSES OF INSUFFICIENT REVENUES TO RECOVER BPA'S COSTS INCLUDING REPAYMENT OF THE FEDERAL TREASURY IN THE RATE ESTABLISHMENT PROCEDURE, IT WOULD GREATLY ENHANCE FERC'S ABILITY TO REVIEW THOSE RATES AND CONFIRM AND APPROVE SUCH A RATE IN A MORE EXPEDITIOUS MANNER.

THE PROVISIONS OF H.R. 3177 ARE DIRECTED AT PROCEDURES IN THE RATE ESTABLISHMENT AREA, AND DO NOT DIRECTLY AFFECT FERC'S ABILITY TO REVIEW SUCH RATES. INDIRECTLY, HOWEVER, ANY PROCEDURE OR REQUIREMENT WHICH RESULTS IN A MORE COMPLETE DEVELOPMENT OF A RECORD UPON WHICH BPA RATES ARE FOUNDED WOULD GREATLY ENHANCE THE COMMISSION'S ABILITY TO REVIEW THOSE RATES FOR ON A MORE EXPEDITIOUS AND COMPLETE BASIS.

THIS CONCLUDES MY PREPARED STATEMENT. I WOULD BE PLEASED TO RESPOND TO ANY QUESTIONS YOU MAY HAVE.

STATEMENT OF

RICHARD FIDDLER

CITY OF SEATTLE, CITY LIGHT DEPARTMENT

October 28, 1983

Before the

SUBCOMMITTEE ON MINING, FOREST MANAGEMENT

AND THE BONNEVILLE POWER ADMINISTRATION

COMMITTEE ON INTERIOR AND INSULAR AFFAIRS

U.S. HOUSE OF REPRESENTATIVES

Mr. Chairman, members of the Subcommittee:

My name is Richard Fiddler. I am employed by the City of Seattle, Washington, in the Conservation and Solar Division of Seattle City Light, the City's municipally-owned electric utility, and I am testifying on their behalf today. Seattle City Light began conservation programs in 1974 and chose to rely on conservation as a resource in 1976, well before passage of the Regional Act. Seattle closely followed the development of the conservation provisions of the Regional Act, and appreciates the opportunity to discuss with you a serious current problem in regional conservation implementation.

The conservation contracts between BPA and the region's utilities, which had heretofore provided regional funding and coordination for conservation, expired September 30, 1983. BPA has offered long-term replacement contracts, but has insisted on certain contract provisions in them which have made it imprudent for many of the largest utilities in the region, including Seattle, to sign them. As it now stands, about 50 to 70 percent of the region's utility load will probably not have access to regional conservation programs. While we believe that no party intended this current impasse, it is a significant setback from the situation a few months ago when BPA programs were available regionwide.

Congress should not be surprised that there are some rough places in the road to a mature, effective regional conservation program. Conservation resources inherently differ from generation resources in the institutional arrangements they require and in their flow of costs and benefits. Much has been learned in recent years.

We are concerned, however, about BPA's haste to enshrine in a long-term contract certain institutional arrangements which they prefer, but which are still the subject of intense debate. At issue are not only arguable concerns about fairness but also the basic facts upon which a judgment should be based. For example, in the 1982 BPA Rate Proceeding, BPA offered a clear discussion of how the benefits of a regional conservation program are distributed: to BPA ratepayers, to utilities, and to individual retail consumers who adopt conservation measures. We essentially concur with BPA's 1982 discussion. In the 1983 Rate Proceeding, BPA allocated its conservation costs based on a revised analysis of benefits which ignored several crucial features of its 1982 discussion. In fact, we believe that the controversial conservation contract charge adopted by the Administrator last month would have been impossible to justify under the 1982 discussion. BPA did not respond to our requests to justify the changes in their analysis.

In a situation like this, we submit that BPA's policy of demanding utility acquiescence on the disputed issues as a condition of continued participation in regional conservation programs is inappropriate, and counter to the best interests of the region and its ratepayers.

Let me review briefly the key conservation elements in the Regional Act and then some of the events preceding the current impasse between BPA and many of the largest utilities.

- In the Regional Act, conservation and generation are both resources to meet supply/demand imbalance (Sec. 3(19)). Conservation is the first priority resource (4(e)(1)) and is eligible for a 10% cost advantage (3(4)(D)).
- Conservation is to be weighed against resource alternatives in the Regional Plan (4(e) and 6(a)(1)).
- Conservation resources shall be acquired by BPA in partnership with utilities and local entities where possible (6(e)(2)). Pursuant to the Regional Act, the Northwest Power Planning

Council (NPPC) was formed in 1981. The NPPC adopted a Regional Plan in April 1983 which included conservation as a priority resource. Seattle participated extensively in the Plan's development. Staff from the utility, the Mayor's office, and the City Council all took part; the Mayor and the superintendent of City Light testified to the NPPC; and the Mayor and City Council determined Seattle's recommendations on the Plan by Resolution. The Regional Plan's "Two-year Action Plan" called for conservation investment and regional "capability-building" in the near term despite the current surplus. Correctly anticipating the direction of the Plan, BPA and the region's utilities entered into workable short-term contracts under which conservation resources have been acquired to date. Conservation has both been adopted in the Plan and been working in the region.

Now, however, there is danger that our momentum will be lost. The short-term contracts have expired. Discussions over long-term replacement contracts failed to reach a mutually acceptable conclusion, and BPA did not grant requests from Seattle and other utilities to extend the short-term contracts until agreement could be reached. Instead, BPA offered long-term contracts knowing that they were opposed by many utilities. Some utilities, principally smaller public utilities without their own sources of power, were not particularly disadvantaged by the long-term contracts, and several have signed.

There are two major unresolved issues in the long-term contracts. The first major issue is BPA's insistence on the right to amend many of the provisions of the contract concerning program operations and reimbursement unilaterally, after consultation with utilities. We believe that such a provision, except for health and safety concerns, fails to acknowledge the partnership role for utilities which was envisaged by us and, we believe, by Congress. BPA's legitimate program needs can be met without such a one-sided relationship.

The second major issue is that the long-term contract grants BPA new authority to impose a conservation contract charge on participating utilities. The methodology and amount of the charge are to be determined periodically by BPA concurrent with rate proceedings. In the current period, the charge is assessed only on utilities with their own generation. In 1985, for example, Seattle's contract charge would be about $2.5 million per year if we signed the long-term contract, a very substantial sum. In addition, Seattle incurs a 20-year obligation with a present value of at least $14 million if we sign. BPA currently has no authority to impose such charges on utilities; Seattle and several other utilities believe such a charge is counter to Section 7(g) of the Regional Act. In any case, it is unwise.

Seattle's principal concerns about the contract charge are that it inevitably compromises the equivalent treatment of conservation and generation resources and that it provides a severe financial disincentive to some utilities which make it imprudent for them to sign contracts. Seattle put these concerns forward in the 1983 rate case, beginning with initial testimony in May. As an alternative, Seattle proposed to continue in place the conservation cost allocation method chosen by BPA in the 1982 Rate Proceeding, which spread conservation costs evenly to all firm loads. Like the short-term contract, this method may have been imperfect, but it was working.

In later testimony and briefs, Seattle was joined by four other public utilities: Tacoma City Light and Chelan, Douglas and Grant County PUDs. Closely related concerns were raised by the investor-owned utilities. Despite a strong record supporting our concerns, BPA repeatedly dismissed the disincentive as insignificant -- even as its seriousness became self-evident.

BPA's final revision of the contract charge, intended to relieve the disincentive, did not generally help. BPA failed even to acknowledge the existence of conservation/generation equivalence as an issue until the Administrator's final Record of Decision (pp. 144-5), where it was treated casually. We are disappointed that these fundamental concerns were not taken more seriously.

Conservation/generation equivalence is one of the central concepts of the Regional Act. Understanding the costs and benefits of acquisition of, for example, a 60-mill/kwh generation resource from a utility by BPA is relatively simple: BPA pays the full cost of the new resource to meet load growth, and receives the power produced for sale. For most load growth, the unit cost of the new resources will exceed the melded, average, unit cost embodied in the current wholesale rate, so the new resource will cause an increase in some or all BPA power rates. Except insofar as it may share in a regionwide rate increase, the particular utility which develops the generation resource and offers it to BPA comes out even financially, since BPA reimburses its actual costs for the new resource. This analysis of the acquisition of a generation resource defines the yardstick for conservation/generation equivalence.

However, the transactions for a conservation resource are more complex, because the parties include individual retail consumers as well as BPA and utilities. For a 60-mill conservation resource to be equivalent to a 60-mill generation resource, each of the parties must believe that they are at least as well off if conservation is chosen. Under this criterion, BPA may contribute up to the "yardstick" limit: the net cost that BPA would have incurred had generation been purchased and resold at a lower rate.

The utility in which a particular conservation load reduction takes place generally does not receive a financial benefit. The utility perceives reduced cost of BPA power purchases, but also reduced revenue from sales to the affected retail consumer. The net effect can be positive or negative, depending on the relative amounts of the retail and wholesale rates. For Seattle City Light, the net effect is negative for residential conservation measures, by about 15 mills/kwh. In general, public utilities are about neutral: no significant net benefit or cost. The individual retail consumer, on the other hand, has a clear benefit through reduced retail power purchases. As is the case with generating resources, the BPA reimbursement payments provide no benefit to utilities, because they are passed through entirely to customers or their contractors, and BPA administrative reimbursements to utilities are for services rendered, and often do not fully cover utility costs.

The conclusion that utilities do not benefit from BPA conservation programs is surprising to many. It is apparently surprising to BPA, because very large contract charges are assessed generating utilities based on their alleged benefit. Prior to passage of the Regional Act, the situation was quite different. Then, utilities had to provide for their own load growth, as witness their expensive commitments to Washington Nuclear Plants 4 and 5. Then, many invested in their own conservation as a cheaper alternative. Now, for any utility purchasing power from BPA, a load reduction in the utility's service area automatically reduces BPA's obligation to meet that load.

The benefits of conservation which formerly came to utilities now automatically pass to BPA. This severely inhibits both a utility's willingness to invest in conservation on its own -- absent BPA reimbursement under contract -- and its willingness to sign a contract which obligates it to pay a contract charge. If a generating utility takes either action in order to promote conservation, it leads to a retail rate increase which could have been avoided.

The contract charge is like an entry fee, assessed generating utilities only, for the privilege of offering conservation resources to BPA at cost. No such fee would be charged for a generating resource. A generating utility subject to a contract charge is clearly better off offering a new generation resource to BPA to meet load growth than if it offers a conservation resource of equal total cost to prevent load growth. The contract charge therefore runs counter to a central feature of the Regional Act.

What are the counter-arguments to the concerns we have raised here? After all, BPA and some utilities actively support the contract change. Several points have been made, though we believe none are decisive.

1. Some say that all utility loads "benefit from conservation," including loads not served by BPA, and therefore all loads should contribute to payment. This argument implicitly assumes that conservation is some sort of windfall benefit, not a real, specific resource. If all loads are eligible for the windfall, all should pay.

Real beneficiaries other than BPA do exist, including those individual consumers who install conservation measures. These consumers now usually share in the cost as well, so their benefits are earned. Such cost-sharing, properly done, is appropriate and does not necessarily hinder the acquisition of conservation resources or their equivalent treatment.

2. BPA relied on "generator/non-generator equity" as its dominant criterion. A variant of the previous argument, this criterion essentially requires that utility payment for conservation resources should largely be proportional to utility load: each kilowatt hour should share equally in costs of meeting regional load growth. This cannot be done if all the costs of conservation are recovered through rates. Since generation costs are clearly recovered through rates, the effect of employing this criterion is to violate conservation/generation equivalence and to sacrifice (or else severely penalize) the conservation potential of generating utilities. Its employment has also led to accusations that such utilities "won't pay their fair share," despite the absence of utility benefit.

This is probably the most valid counter-argument. The Regional Act requires BPA to acquire new resources to meet the load growth of all regional utilities with power sales contracts, whatever proportion of their load is currently served by BPA. To the extent that these new resources are more expensive than current BPA rates, the cost of meeting these loads will drive up BPA rates. Utilities which serve all or nearly all their load from BPA purchases will bear a higher proportion of the resulting costs of regional energy growth than utilities which purchase only a small proportion from BPA. This is true for all resources, conservation and generation, and the non-generators believe it is unfair. (Seattle and the public generating utilities are in an intermediate position, typically serving between one-third and two-thirds of their load from BPA purchases.)

The generating utilities, for their part, point to the benefit received by BPA because independent utility generation reduces BPA's obligation to serve utility loads. Without these generating resources in place, BPA would have had to acquire resources much earlier, with attendant higher cost and risk. Actions taken by utilities to provide generation resources prior to the Regional Act should, they argue, hardly be the occasion for a penalty charge which discounts the value of conservation resources in their service area both to their retail customers and to the region.

As is often the case with equity arguments, a case can be made for either perspective. Unfortunately, the generator/non-generator equity concern is deeply rooted in the resource acquisition provision of the Regional Act, and BPA's attempt to resolve it brings up other inequities with severe consequences.

3. It is argued that inequities for utilities paying contract charges can be resolved by utilities at the local level, between conservation participants and non-participants. This is advanced in the Administrator's Record of Decision (p. 143).

Such a solution would necessarily involve the transfer of money to reduce or eliminate the avoidable retail rate increases due to the contract charge. In Seattle's case, even under the most favorable assumptions, about two-thirds of every reimbursement dollar for conservation investments would have to be withheld from participants and transferred to ratepayers in general. The proportion almost certainly should be more. Such transfers would cripple the effectiveness of the conservation programs and are contrary to the spirit and almost certainly to the letter of the proposed contract.

4. In the Record of Decision (pp. 144-5), BPA argues that it has considered conservation and generation on equal terms in its resource acquisition studies and that conservation qualified as a cost-effective resource. Then, "each utility can assess its own operating characteristics and determine if it is reasonable to offer BPA a conservation resource or to pursue conservation programs." This discussion glosses over the fact that a utility decision against participation in conservation programs is driven by the inadequate financial terms BPA is willing to offer. BPA must not only study fairly but pay fairly to achieve equivalent treatment of resources.

5. Seattle has been accused of unwillingness to support the Regional Plan. Given our record, it should be apparent that this is not the case. If we did not believe in conservation as a priority resource, we would not be here today.

6. It has been argued that some utilities may just prefer to "go it alone," perhaps out of pride, independence, or irritation with BPA restrictions. This is not an acceptable option for utilities or for the region. Utilities cannot rationally offer incentives

at the regional cost-effectiveness level without BPA support. As noted, none of the benefits of a conservation investment ordinarily go to the utility serving the conserving consumer; instead, the benefits are shared between BPA and the consumer. If costs do not follow these benefits, conservation must become an object of charity on someone's part rather than a resource.

I now wish to turn to recent events and possible short-term solutions. Seattle carefully considered signing the BPA long-term contract even though it did not correspond to our preferences. However, our financial analysis showed that by signing we would incur very large obligations. Even making the most favorable assumptions: that despite the absence of a contract, Seattle would continue to self-fund conservation indefinitely at a level equal to our proposed 1985 budget in real dollars; that there would be no change in methodology in future rate cases; and that there would be no increases in the BPA contract charge factors, even for inflation; we calculated that it would take over 14 years to break even. Under more realistic assumptions, break-even might never occur. For us, signing is not a prudent decision in the short or long term.

As a result, the Mayor and City Council declined to sign the BPA contract, but have expressed a desire to work with BPA to resolve our differences. We want and need a fair contract.

It has been and remains Seattle's objective to work out an equitable, mutually beneficial, stable relationship with BPA. However, our programs are seriously hurt in the short-run. Without BPA reimbursements, Seattle was forced to choose between rate increases and dismantling our programs. The Mayor has recommended a 1984 budget for City Light which reduces our goals but preserves the program for now. Even so, we are looking toward the loss of 19 full-time positions and a 15-20% reduction in conservation expenditures. Even with these reductions in program, conservation has become a visible component of increases in City Light's 1985 revenue needs.

In the short run, Seattle believes that it is important for BPA and the utilities to reach an understanding promptly so that conservation funding to utility programs can be restored, at least on an interim basis. This would give all the actors the time to reach a mutual understanding of the facts of conservation financing, time which is clearly needed. It is no wonder that we cannot agree on the policies if the underlying facts are still at issue.

We do not believe that our current impasse with BPA results from malice on anyone's part. We believe instead that it results from differing perspectives on a complex problem. In the spring of this year, BPA's redefinition of the form of the proposed contract charge and BPA's substantial revision of its analysis of conservation benefits dramatically redefined this problem. Since then, BPA has believed that the rules of the Rate Proceeding prevented them from engaging in extensive discussions with us; only now can discussion of some of the fundamental issues begin. In such a circumstance, we believe that BPA should contribute to the maintenance of conservation programs in some manner so that good faith attempts to resolve the problem can proceed. For our part, we commit to participate fully and openly in such an effort.

Seattle believes that Congress can play a constructive role by encouraging an orderly, long-term resolution of this problem, and also by encouraging protection of utility conservation capability in the meantime. Conservation is too central to the Regional Act and too important an undertaking for the region to accept failure. Thank you for your continuing interest in this issue and for hearing our concerns.

SUPPLEMENTARY TESTIMONY
OF RICHARD FIDDLER
CONCERNING LEVEL OF CONSERVATION FUNDING

Seattle agrees with the NPPC and with BPA that conservation resources should be acquired in the next few years despite the surplus. We would like to add to the discussion a plea for program stability.

Conservation must be marketed to many consumers -- predominantly small consumers -- to be a reliable resource. This requires the institutions which deliver conservation -- utilities and state governments, for example -- to develop and maintain an extensive capability to market conservation. Seattle's experience suggests two points:

First, it is important to maintain staff stability. A new program must be staffed with skilled people, with new job descriptions, who are then trained in new work practices and marketing techniques. The process takes time and money, and therefore programs should be as free from arbitrary change as possible. Once in place, we cannot shut down or suddenly redirect this conservation delivery system without substantial costs. It is not as easy as throttling back an existing thermal plant. Conservation has flexibility, but within limits.

Second, customers, especially small customers, also need program stability. Some of the arrangements for sharing the cost of conservation investments are rather complex. It does not help the marketing of conservation to have continued changes in the rules. Conservation programs should be kept as simple as possible, and the likelihood that changes will cause staff and customer confusion should be recognized.

SUPPLEMENTARY TESTIMONY
CONCERNING INDOOR AIR QUALITY

Seattle conducted an extensive review of indoor air quality and residential weatherization during development of our own financing program in 1980 and 1981. This work occurred prior to BPA's program development and announcement of program restrictions for air quality reasons. A copy of our review has been given to the Subcommittee staff for your information, but I can summarize its conclusions.

First, we agree that indoor air quality is a real concern which cannot and should not be dismissed. Second, and here we may differ from BPA, indoor air quality concerns cannot be reliably dealt with by any BPA or utility decision concerning weatherization.

Indoor air pollution is strongly dependent on the presence of pollution sources. If sources are absent, a tight, well-weatherized house is fine. If sources are present in strength, a leaky, unweatherized house can be a serious problem. The control of pollution sources can only be done by builders and residents; utilities can neither control them nor even be sure what sources are present over an ordinary year.

Since the purpose of house tightening is the reduction of air exchange rates to reduce heat loss, a successful job will reduce the dilution of any pollution sources which are present. This will ordinarily increase pollution levels to some degree. Seattle, therefore, opted in its program for disclosure to the resident that, if sources are present, house-tightening measures may aggravate the problems. Conversely, BPA chose to exclude house-tigtening measures from their program unless houses appeared to be at very low risk.

We hope that BPA's studies for their draft Environmental Impact Statement will lead them to eliminate restrictions on these valuable conservation measures. (Seattle estimates that 95% of its participating customers are ineligible for storm windows under the BPA Program.)

BPA has now released a draft Environmental Impact Statement, to which Seattle will respond. We do note at this time that BPA in its public discussion continues to treat indoor air quality problems as weatherization-related, when in fact the relationship is very tenuous. We do know that if we forego effective conservation measures, new generation, with its own environmental impacts, will be required to make up the lost conservation. Similarly, measures such as air-to-air heat exchangers can mitigate many of the effects of house tightening possibly at lower cost than new generation; we seek a discussion in the EIS allowing comparison of such alternatives.

However, we are pleased that BPA continues to consider including more conservation measures in its program, and hope that the draft EIS contributes to that result.

Testimony of
PAUL L. HATHAWAY,
Senior Vice President
Northwest Natural Gas Company

Before the
U.S. HOUSE OF REPRESENTATIVES
SUBCOMMITTEE ON MINING, FOREST MANAGEMENT
AND
BONNEVILLE POWER ADMINISTRATION
OF THE
COMMITTEE ON INTERIOR AND INSULAR AFFAIRS
WASHINGTON, D.C.
FRIDAY, OCTOBER 28, 1983

Good afternoon. I am Paul Hathaway, Senior Vice President of Northwest Natural Gas Company. My business address is One Pacific Square, 220 N. W. Second Avenue, Portland, Oregon. I am responsible for the operation of the Company's Engineering and Gas Supply Division, the Distribution and Customer Service Division, and Governmental and Public Relations Department.

Ronald Miller, President and Chief Executive Officer of Northwest

Natural Gas Company, was unable to attend this oversight hearing due to previously arranged engagements. Mr. Miller was most interested in appearing and sends his sincere regrets for missing this opportunity to personally state very serious concerns he has with the Northwest Power Planning Council's recently adopted Regional Energy Plan. Both Mr. Miller and I, however, thank Chairman Weaver for the invitation to testify on these matters of vital importance to energy consumers of the Pacific Northwest.

At the outset, let me say that my comments regarding the Regional Energy Plan reflect not only the views of my Company, but also of most of the other natural gas distribution companies serving the Pacific Northwest region, and the gas pipeline company which serves all of us, the Northwest Pipeline Corporation.

[our ~~The~~ industry participated very actively before the Regional Power Council during the two-year period when the Regional Plan was being prepared. Besides offering oral testimony and exhibits on a number of occasions, our industry remained in continuous contact with the Council's technical staff.] ①

The constant and unmistakeable theme underpinning all our presentations to the Regional Council during this period was, simply stated, that the natural gas industry would find intolerable and would vigorously oppose a Plan which provided financial subsidies, incentives and other inducements to consumers, and others, to switch to electricity as a source of energy, or to choose electricity in the first instance.

We categorically repeated our industry's disagreement with any program or energy policy which signaled any preferential treatment for electricity.

Aside from the very obvious anti-competitive interference such programs or policies would impose upon the energy market, and the hindrance they would cause to the economic well-being of the region's ratepayers as a whole, the effects of such programs or policies would clearly be diametrically opposed to the purpose of the Pacific Northwest Electric Power Planning and Conservation Act. That Act demands electric load reduction through conservation of electricity. The financial incentives that appear in the Plan, on the other hand, guarantee electric increases, even though offered under the guise of purchasing "conservation".

The Regional Plan was adopted on April 27, 1983. Our industry was appalled at the clear favoritism shown the electric energy industry, and the clear anti-competitive, discriminatory interference in the energy market-place. Accordingly, our industry filed a law suit on July 28, 1983, in the United States Court of Appeals for the Ninth Circuit in San Francisco, California.

Your Subcommittee's legal counsel, Dan Meek, met with our attorney and a representative of our industry in Portland, Oregon, on August 24, 1983, for the purpose of discussing the issues raised in the fourteen claims stated in the Petition for Review. Because your counsel has had the opportunity to review our petition with us and with the Regional

Power Council's staff, I shall provide your Subcommittee with five (5) copies of the petition and will now only highlight the major areas of misconduct alleged in the petition.

It is important to note that our petition does not challenge the Regional Power Act. Rather, it challenges the actions of the Northwest Power Planning Council as promulgated in its Regional Energy Plan. The respondents include the Council members, the Administrator of the Bonneville Power Administration, and the Secretary of Energy. The latter two respondents are named because of their obligation to implement the Plan. The petition seeks a declaration from the Court that certain programs required by the Plan violate the Regional Power Act, and an injunction against those programs which our industry considers to be the most harmful. The petition also asks the Court to remand the Plan to the Council for rewriting in accordance with any findings the Court may make.

Let me stress two points before outlining the major issues. First, the natural gas industry is certainly not opposed to conservation of energy. We support that policy, and have demonstrated that commitment consistently through our own conservation programs. Second, the natural gas industry is against payment of financial incentives and subsidies by the Bonneville Power Administration for purposes of influencing consumer choice of energy forms. This means that our industry also does not want such incentives to be paid by the Bonneville Power Administration to consumers to induce them to choose natural gas. We merely want to be allowed to compete on an equal basis in serving the energy consumers of the Pacific Northwest.

There are three main issues raised in the petition. First, we believe the Plan violates the Regional Power Act by calling for the payment of the first cost of electric boiler installations for industries presently using fossil-fueled boilers, and by providing for special rates which may be non-compensatory, all for the purpose of marketing interruptible electric energy in the region. The Plan is particularly offensive in this respect because it sets a long-term discriminatory policy, couched in terms of purposeful displacement of fossil-fueled boilers. The Council has responded that it did not intend to convey the impression that it supports non-compensatory electric rates. Our industry remains concerned, however, that this highly influencial energy planning body has quite improperly conveyed the impression in its Plan that displacement of fossil fuels is the preferred energy policy for the region. This unacceptable impression must be corrected.

Second, our industry has provided undisputed proof that the Plan's model conservation standards for new residential and commercial buildings are not cost-effective for natural gas-heated structures. The Council has acknowledged that it did not study the cost-effectiveness of the model standards for structures utilizing natural gas for space heating. Indeed, in Volume Four of the Plan, the Council acknowledges that if the model conservation standards were applied to all new structures (i.e., a single fuel code applicable to all new structures), the most likely result would be *more* homes using electricity for heating. The estimated electric load increase would be 300 megawatts. Yet, Appendix J to the Plan, which is most likely the document governmental implementors will look to in adopting the model standards, unquestionably applies to structures using natural gas. We have pointed this out to the Council's staff during recent weeks, and are hopeful this problem may be resolved satisfactorily to all concerned.

Finally, the petition identifies a number of programs in the Plan which are fraught with anti-competitive aspects and which will, if implemented by the Bonneville Power Administration, do irreparable harm to our industry and, consequently, the region's economy. The basis of these claims is the Regional Power Act's definition of the word "conservation". Section 3(3) of the Act defines "conservation" to be the reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution. The Act conspicuously fails to require reduction in electric power consumption only though more efficient uses of electric energy. Our industry maintains that where the use of natural gas is more cost-effective to the region for a given purpose than is the use of electricity, and such use reduces electric power consumption, the use of natural gas in those instances would be "conservation". The Bonneville Power Administration, however, insists that natural gas use is not and cannot be "conservation". Rather, BPA insists natural gas is a fourth priority resource under the scheme of resource purchases set forth in the Act. Bonneville's position defies logic, as well as defying the Act. What better means of conserving electricity is there for the region than to increase its availability by substitution of it with natural gas, particularly when it is more cost-effective for the region? Since our industry does not ask for financial incentives, and indeed is opposed to them, how is such use of natural gas not cost-effective for the region? Yet, the use of natural gas as a substitute for electricity was not considered in the Plan. There was no consideration of the cost-effectiveness of the voluntary use of natural gas in the Plan to substitute for and hence to conserve electricity.

Frankly, we fear BPA's position is motivated by two overpowering concerns. First, BPA is concerned that if natural gas is treated as a conservation measure, BPA will have to pay for the installation of natural gas equipment and the fuel itself. Our industry's position regarding subsidies should dispel this fear. Second, BPA is concerned about the present short term electric energy surplus. Bonneville feels that it is in its best interest, and also in the best interests of its utility customers, to aggressively market all the electricity it can in the region during this surplus period, thus leaving no room for conservation measures utilizing natural gas.

The natural gas industry does not oppose appropriate methods of utilizing electricity as a resource to help our region regain its economic health. Indeed, we favor healthy marketing efforts by all energy distributors. Free competition among energy forms is an economically proven stabilizer of economic health. On the other hand, interference in free-market place decisions of energy consumers through injection of financial subsidies favoring one energy form over another will wreak havoc with our region's economy. We fear that the provision of incentives will further prostrate an economy already in its sickbed, and delay recovery. We are absolutely confident the Court will not countenance any programs which favor one industry at the direct expense of another industry in the same market.

Chairman Weaver's October 12, 1983, letter to Mr. Miller also invites comments on the Administrator's September 30, 1983 decision establishing new rates, and on H.R.3177, the Bonneville Power Administration Fare Ratemaking Act of 1983.

[We did not participate in the 1983 BPA rate case, although we did participate to a limited extent in the 1982 BPA proceeding. Consequently, I feel constrained not to comment on the subject of the 1983 case. At this time we are STUDYING ~~scrutinizing~~ the various new interruptible rates issued by the Administrator. We recognize that the proposed 0.7 cents per kilowatt-hour surplus energy rate will contribute to an already distinctly competitive environment in the industrial sector for natural gas. We are not now in a position to say that such proposed rate is, or is not, compensatory. We can categorically say, however, that it would be immeasurably harmful, and certainly illegal, if BPA were to pay the first cost of electric boiler installations in addition to providing electric energy at such a low rate.

On June 13, 1983, I had the opportunity to appear before the U.S. House of Representatives Subcommittee on Energy Conservation and Power of the Committee on Energy and Commerce, in Seattle, Washington. At that time, I expressed our industry's support of H.R.3177. I am taking the liberty of providing your Subcommittee five (5) copies of the testimony I presented then, for it addressses H.R. 3177, as well as other matters relating to the conduct of BPA's rate proceedings. I hope those comments will assist you in your consideration of the Bill.

Again, thank you for your invitation to participate in these ~~oversight~~ hearings.] 2 I have very much appreciated the opportunity to appear before you. I will be pleased to respond to your questions at this time.

PREHEARING

QUESTIONS AND ANSWERS

SUBMITTED BY

PETER T. JOHNSON

ADMINISTRATOR

BONNEVILLE POWER ADMINISTRATION

FOR THE HEARING

ON

OCTOBER 26,1983

BEFORE

HOUSE COMMITTEE ON INTERIOR AND INSULAR AFFAIRS

SUBCOMMITTEE ON

MINING, FOREST MANAGEMENT AND BPA

1. HISTORY AND PROJECTIONS OF BPA COSTS, RATES, REVENUES, AND LOADS

QUESTION 1.a How have BPA's costs changed since 1978? Please provide at least annual costs disaggregated in a manner similar to column C of Table 4 of the March 1983 COSA and show separately the annual repayment of principal and annual payment of interest on (1) BPA debt and (2) Corps and Bureau projects. Please plot on a line graph the cost changes for at least these categories: FCRPS, WPPSS, residential exchange (cost net of revenue from exchanging utilities), conservation, fish & wildlife, interest, and principal repayment.

RESPONSE Table 1.a-1 entitled Federal Columbia River Power System Schedule of Operating Expenses appearing on the next page presents the requested information. However, the data for fiscal year 1983 is unaudited and is based on preliminary information prior to reclassification and audit adjustments.

In addition to the above table, Table 1.a-2, Schedule of Amortization and Unpaid Annual Expense for The Federal Columbia River Power System and Graphs 1.a-1 through 1.a-7 outlining the historical pattern of our key operating expenses has also been provided.

Table 1.a-1

FEDERAL COLUMBIA RIVER POWER SYSTEM
Schedule of Operating Expenses
Projected for Fiscal Year 1983 and Audited Results for Fiscal Years Ended September 30, 1982, 1981, 1980, 1979, and 1978

	1983 4/	1982	1981	1980	1979	1978
			(In millions)			
OPERATING EXPENSES:						
Operation and Maintenance:						
BPA						
Operation	$ 111.5	$ 114.0	$ 95.9	$ 78.8	$ 55.4	$ 48.3
Maintenance	30.0	32.9	31.2	28.0	25.9	23.5
Conservation	5.0	1.9	1.3	1.2	.6	.2
Fish and Wildlife	5.8	2.0	.2	0	0	0
Corps						
Operation	27.4	22.5	21.5	19.3	16.0	15.5
Maintenance	26.3	19.1	15.9	13.1	13.5	11.2
Bureau						
Operation	6.2	6.0	5.4	5.1	4.5	4.2
Maintenance	10.5	10.1	8.9	8.6	7.2	7.2
Total Operation and Maintenance	222.7	208.4	180.3	154.1	123.1	110.1
Purchased Resources:						
Trojan	46.1	40.8	40.7	76.7	22.3	30.8
Hanford	8.4	11.2	5.3	3.8	0	17.5
WPPSS #1	201.4	173.4	99.4	22.9	0	0
WPPSS #2	269.7	168.1	106.2	70.6	0	0
WPPSS #3	161.9	40.0	0	0	0	0
Residential Exchange						
IOU's	535.9	428.2	0	0	0	0
Public's	7.7	.2	0	0	0	0
Purchased Power for Resale	19.6	76.6	14.3	7.6	1.8	2.1
Regional Act	4.9	2.0	0	0	0	0
Other	1.5	5.0	3.7	1.1	1.1	.7
Total Purchased Resources	1,257.1	985.5	269.6	182.7	25.2	51.1
Interest Expense:						
BPA:						
Appropriated Funds	70.4	66.6	67.1	66.2	58.8	59.0
FCRTSA 1/ borrowing	113.9	85.5	49.6	35.2	24.6	6.2
AFUDC 2/	(24.1)	(20.0)	(18.6)	(19.2)	(12.3)	(6.4)
Corps:						
Appropriated Funds	124.2	113.8	109.0	104.8	95.6 3/	86.6
AFUDC 2/	(15.1)	(11.7)	(19.5)	(15.2)	(10.3)	(12.7)
Bureau:						
Appropriated Funds	21.8	20.6	20.2	19.5	18.9	17.6
AFUDC 2/	(2.2)	(3.0)	(1.3)	(7.5)	(7.3)	(8.1)
Net Interest Expense	288.9	251.8	206.5	183.8	168.0	142.2
TOTAL OPERATING EXPENSES	$1,768.7	$1,445.7	$656.4	$520.6	$316.3	$303.4

1/ Federal Columbia River Transmission System Act.
2/ Allowance for funds used during construction.
3/ $39,765 of the Corps interest was deferred in 1979, fiscal year.
4/ Unaudited, based on preliminary results.

Table 1.a-2

FEDERAL COLUMBIA RIVER POWER SYSTEM
Schedule of Amortization and Unpaid Annual Expense
Projected for Fiscal Year 1983 and Audited Results
for Fiscal Years Ended September 30, 1982,
1981, 1980, 1979, and 1978

	1983 a/	1982	1981	1980	1979	1978
			(In millions)			
AMORTIZATION OF APPROPRIATED FUNDS:						
BPA	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
CORPS	0	0	2.6	.2	(1.0)	7.9
BUREAU	0	0	(.9)	(.1)	1.9	(.8)
TOTAL AMORTIZATION	$ 0	$ 0	$ 1.7	$ .1	$ .9	$ 7.1
UNPAID ANNUAL EXPENSE:						
BPA	$ 65.3	$ 43.3	$ (3.1)	$ 13.9	$ 58.8	$ 0
CORPS	0	.4	(.8)	(.1)	39.8	0
TOTAL UNPAID ANNUAL EXPENSE	$ 65.3	$ 43.7	$ (3.9)	$ 13.8	$ 98.6	$ 0

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a/ Unaudited, based on preliminary results.

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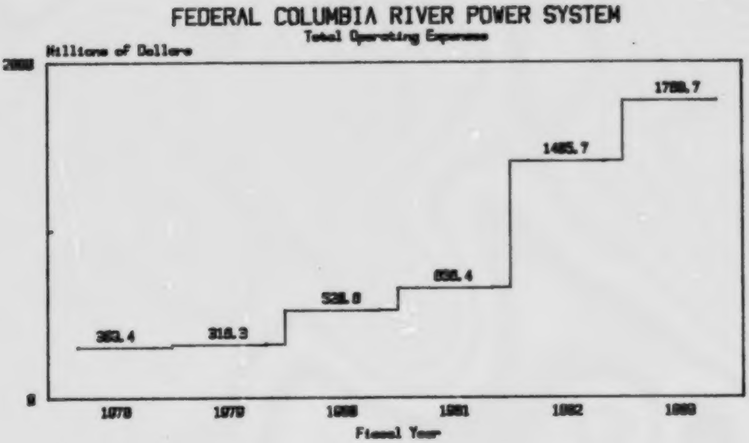
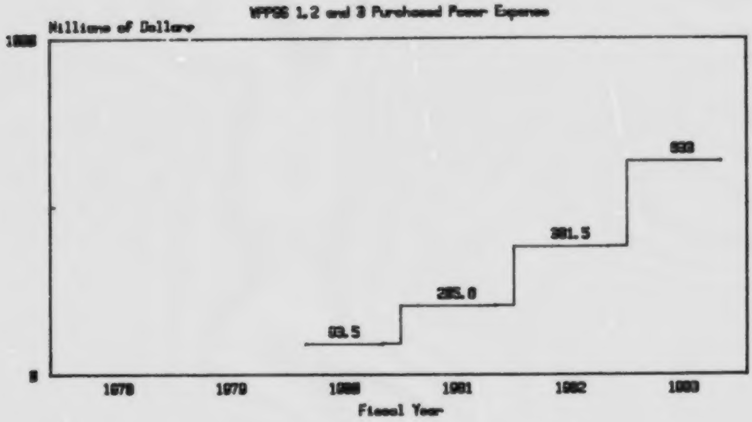
Graph 1.a-1



Graph 1.a-2



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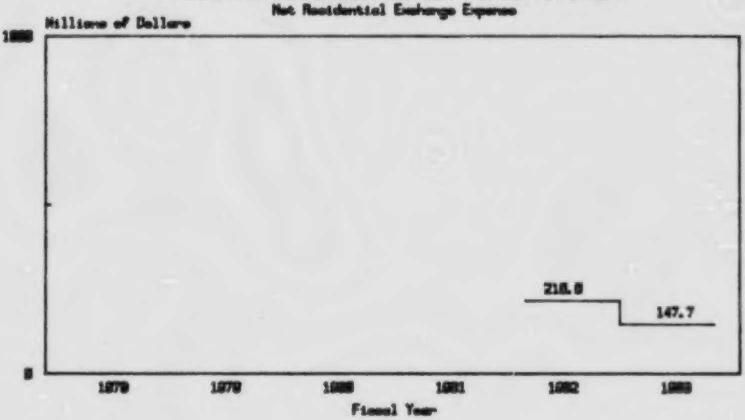
Graph 1.a-3

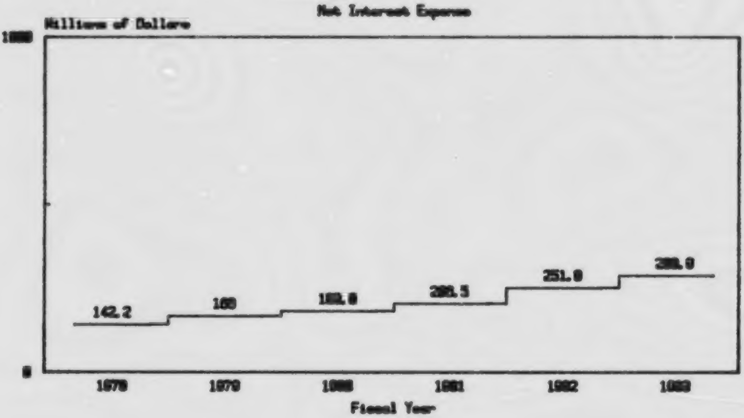
FEDERAL COLUMBIA RIVER POWER SYSTEM

Net Residential Exchange Expense



Graph 1.a-4

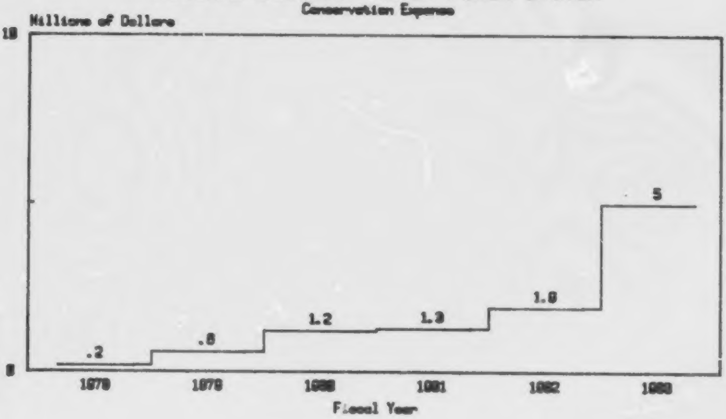
Net Interest Expense



Graph 1.a-5

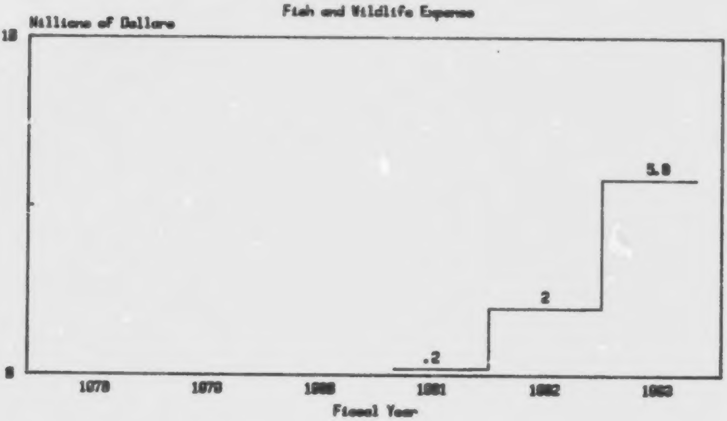
FEDERAL COLUMBIA RIVER POWER SYSTEM

Conservation Expense



Graph 1.a-6

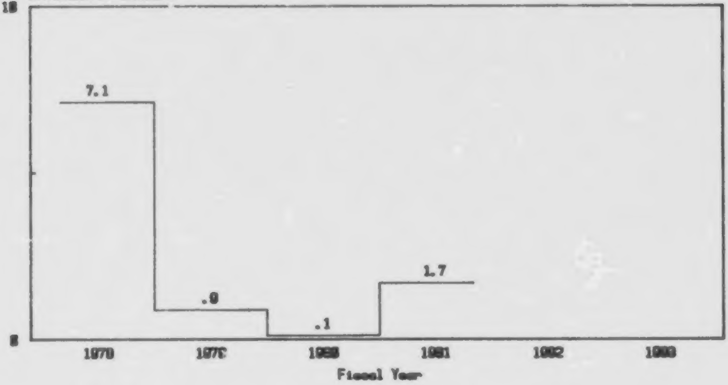
Fish and Wildlife Expense



Graph 1.a-7

FEDERAL COLUMBIA RIVER POWER SYSTEM

Amortization of Appropriated Funds



QUESTION 1.b What have BPA's rates been for each rate category (priority firm, residential exchange, industrial firm, nonfirm surplus, firm surplus, firm capacity, wheeling, etc.) since 1978? Please list customer, demand, and energy charges separately, along with an aggregate price of power for a typical BPA customer in each rate category. Please plot these rate changes on one or more line graphs.

RESPONSE Please see Table 1.b-1 "Wholesale Power Rates" which presents BPA wholesale power and transmission rates for its major rate categories. The wholesale power rates in effect in 1978 became effective on December 20, 1974. All rate increases since that time, including the current proposal, are presented on the table. Table 1.b-2, "Average Rates Under Historical and Projected Rates," provides an average cost of power as opposed to an aggregate price of power for each rate category. An average rate was presented since it is a better measure of the mean cost due to its smoothing seasonal peaks and valleys. Table 1.b-3 "Average Wheeling Rates," indicates the wheeling rates that applied during this period. Graphs 1.b-1, 1.b-2, and 1.b-3 detailing the changes in these rates since 1974 have been provided with the exception of the wheeling rates.

Table 1.b-1

Wholesale Power Rates

Rate Period (Effective Date)	Priority Firm 1/		Industrial Firm 1/		Firm Capacity	Firm Energy	New Resources		Surplus Power		Surplus Energy	Nonfirm Energy
	Demand $/kW /mo.	Energy mills/ kWh	Demand $/kW /mo.	Energy mills/ kWh	Annual/Seasonal $/kW/mo.	mills/kWh	Demand $/kW /mo.1/	Energy mills/ kWh	Demand $/kW /mo.1/	Energy mills/ kWh	mills/kWh	mills/kWh 2/
12/20/74	1.00	1.53	1.08	1.525	1.00/1.30	4.0						3.3
12/20/79	1.57	3.98	1.57	3.98	1.57/1.946	6.1						6.6
07/01/81	2.12	7.19	1.79 3/	4.89 3/	2.12/2.35	10.0	2.12	28.26				7.4
10/01/82	3.06	12.13	1.75 3/	23.57 3/	3.06/2.66	16.4	3.06	25.78	3.06	28.4	28.4	9.8
11/01/83 (proposed)	3.73	14.57	10.32 4/	12.06 3/	3.73/2.42		3.73	24.09	3.85	25.9	31.1	13.9

Where options exist for service under the specific rate schedule, rates for the minimum (least-cost) service were used here. Low-Density Discount, Exchange Adjustment, Supply System Cost Adjustment, Power Factor Adjustment, and other conditional charges are not included in these calculations.

1/ Average of the seasonal rates.

2/ Average rate received for nonfirm energy sales.

3/ Includes value of reserves credit.

4/ Includes Operating Demand charge of $7.34/kW month.

Table 1.b-2

AVERAGE RATES UNDER HISTORICAL AND PROJECTED RATES

(mills/kWh)

	Effective Date of Rate				
Category 2/	12/20/74	12/20/79	07/01/81	10/01/82	11/01/83
Priority Firm	3.7	7.4	11.4	17.6	22.1
Industrial Firm	2.9	6.0	16.1	24.5	26.3
Firm Capacity 1/					
New Resources	-	-	-	-	24.1
Surplus Power	-	-	-	-	31.1
Surplus Energy	-	-	-	28.4	31.1
Nonfirm Energy 3/	3.0	7.2	7.4	8.9	14.2
Firm Wheeling 1/					

Sources: Generation and Sales Statistics, reprinted in the Documentation to the September 1983 Revenue Forecast Study; Summary tables from the September 1983 Revenue Forecast Study.

1/ No energy is sold under this rate category, therefore, no average rate per kWh is available.

2/ Dashed spaces indicate that at those times either no rates existed for those categories or no sales were made.

3/ Displacement/Energy Broker sales are included in 10/01/82 and 11/01/83 Nonfirm Energy average rates.

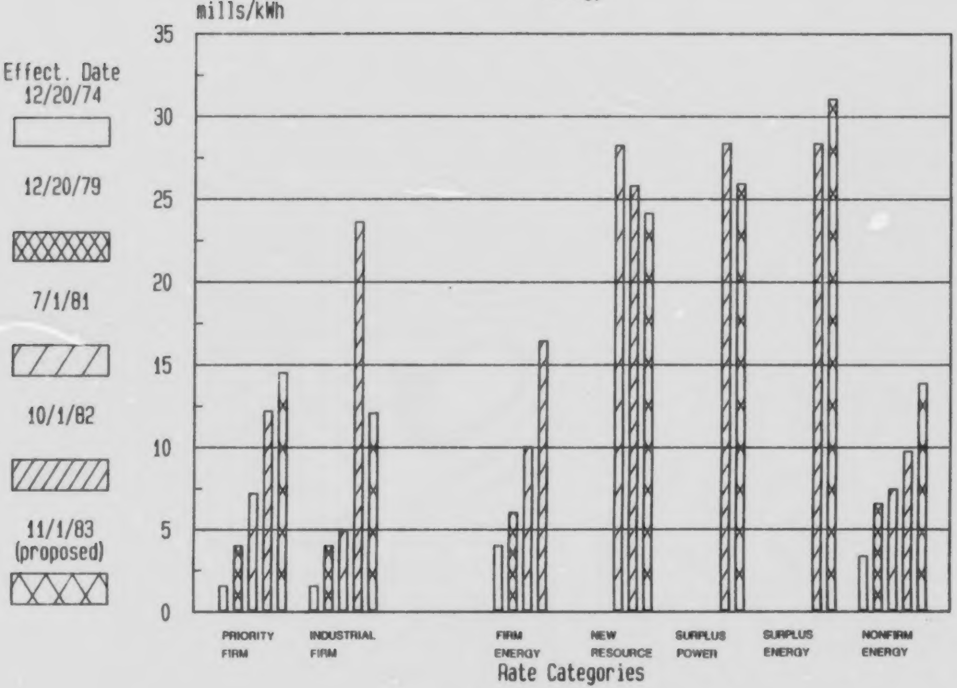
Table 1.b-3
AVERAGE WHEELING RATES

	Effective Oct 1977	Effective Jul 1981	Effective Nov 1983
Firm Wheeling ($/kW-yr)	2.77	4.31	7.05
Nonfirm Transmission (mills/kWh)			
Network	.75	.97	1.38
Network plus SW Intertie	1.25	2.46	3.02

Graph 1.b-1

Wholesale Power Rates

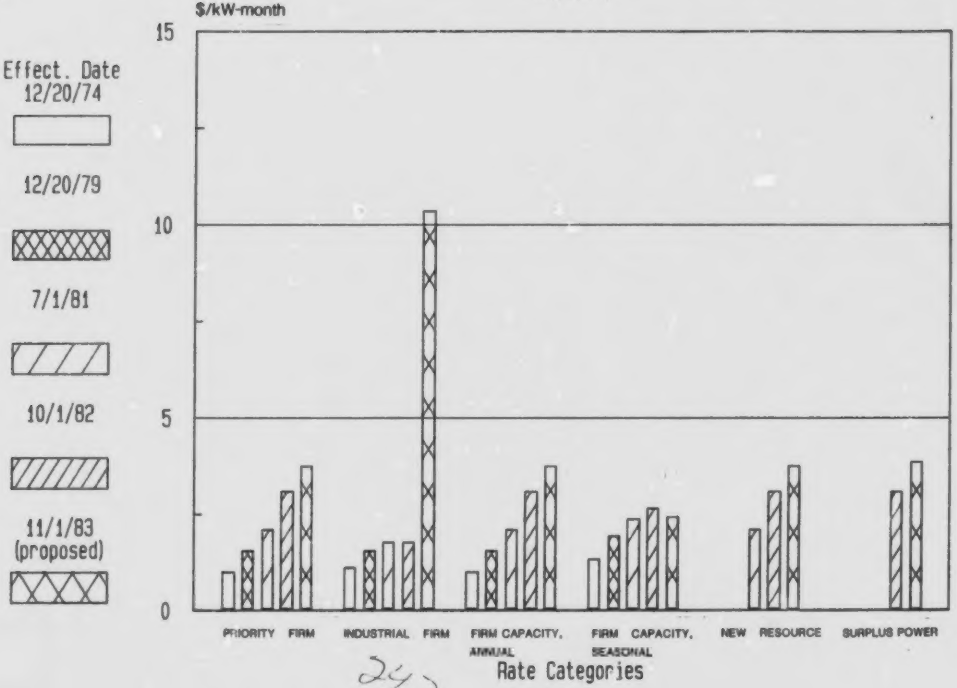
Energy



Graph 1.b-2

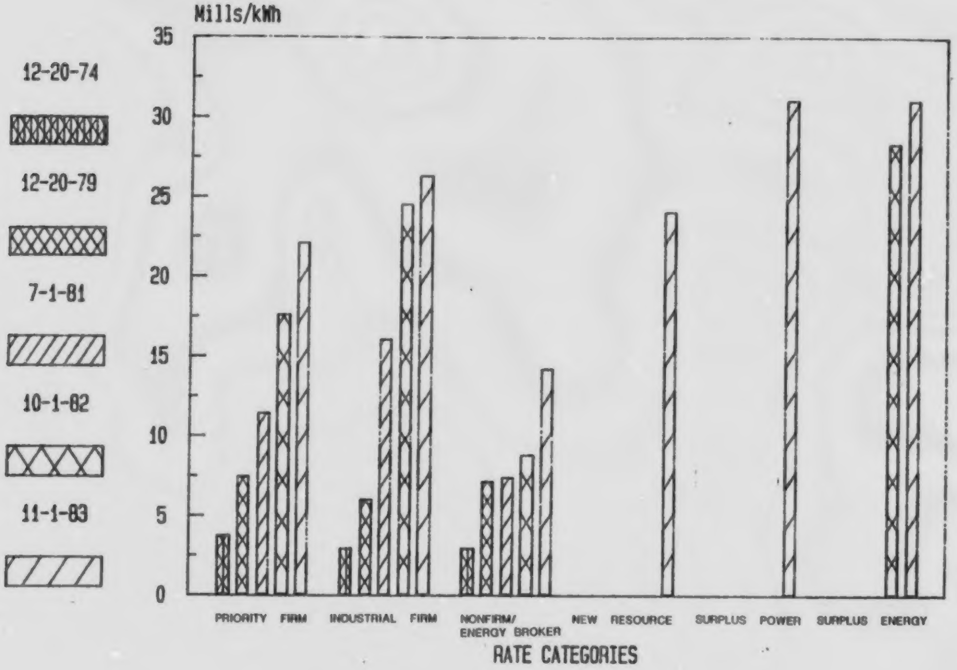
Wholesale Power Rates

Capacity



Graph 1.b-3

AVERAGE WHOLESALE POWER RATES



QUESTION 1.c How much revenue did BPA recover from each rate category during FYs 1978, 1979, 1980, 1981, 1982, and 1983? What is BPA's projection for rate revenue from each category during FYs 1984 and 1985? Please answer for fiscal years (not operating years), and assume that the recently adopted rates remain in effect through September 1985. Please disaggregate surplus energy and power revenues by region (Northwest, California, etc.). Please plot these revenue changes on one or more line graphs.

RESPONSE The accompanying Table 1.c-1, Historical and Projected Revenues, attempts to present revenues recovered and projected to be recovered from each of the mentioned categories. BPA's current rate categories are not the same as those used during FYs 1978, 1979, 1980, and 1981. The accompanying graphs (Graphs 1.c-1 and 1.c-2) of Historical and Projected Revenues compare revenues by rate classification over the period 1978 through 1985. The data used to develop these graphs are from BPA's Generation and Sales Statistics, and are not audited. The tables and graphs assume that the recently proposed rates will be approved and remain in effect through September 1985.

Table 1.c-1

Historical and Projected Revenues

(Fiscal Year)

Class		1978	1979	1980	1981	1982	1983 10/	1984 10/	1985 10/
Revenues ($000)									
Priority Firm 1/		130,124	148,012	254,279	319,068	461,316	634,194	839,393	887,039
Residential Exchange 11/		---	---	---	---	216,593	437,293	714,394	828,859
Industrial 2/		62,670	73,307	114,356	163,729	349,492	419,700	607,474	664,812
Nonfirm 3/	PNW	28,262	16,422	17,760	53,456	48,697	72,287	51,302	52,580
	PSW	17,111	752	27,927	64,024	118,887	149,485	184,912	204,446
Firm Capacity 4/		17,304	23,179	27,461	34,504	47,589	59,162	72,811	73,728
New Resource 5/		---	---	---	---	7,434	0	903	4,800
Energy Broker/ Displacement Sales 6/		---	---	---	---	---	12,134	6,455	6,232
Surplus Power/Energy 7/		---	---	---	---	---	28,495	114,337	186,498
Wheeling 12/		25,562	27,843	27,801	31,197	45,405	53,876	86,229	94,662
Miscellaneous 8/		25,022	16,735	24,502	37,464	33,688	17,615	22,773	26,436
Total 9/		306,055	306,250	494,086	709,422	1,329,101	1,884,242	2,700,983	3,030,092

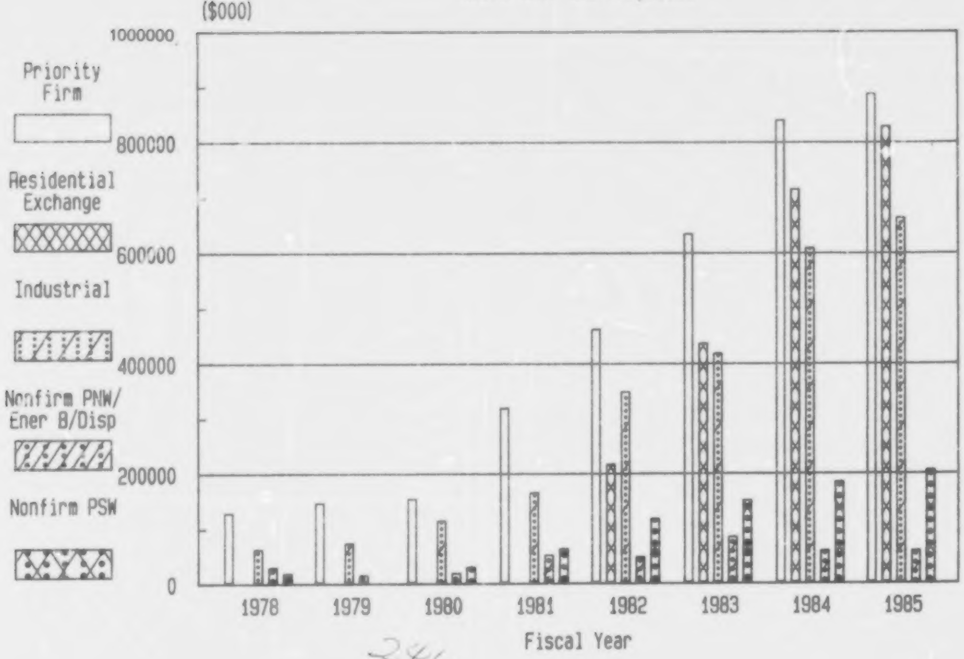
Source: Generation and Sales Statistics -- Prepared by Division of Customer Service, Office of Power and Resources Management, Bonneville Power Administration. (All reports are detailed in the Documentation to the Sep. 1983 Revenue Forecast Study.)

1/ Includes rates: EC-6, EC-7, EC-8, EC-9, PF-1, PF-2, PF-83.
2/ Includes rates: IF-1, IF-2, IP-1, SI-1, IP-2, SI-2 IP-83, IR-83.
3/ Includes rates: H-5, H-6, NF-1, NF-2, NF-83.
4/ Includes rates: F-6, F-7, CF-1, CF-2, CF-83.
5/ Includes rates: NR-1, NR-2, NR-83.
6/ Includes rates: EB-1, Nonfirm Displacement-83.
7/ Includes rates: SE-1, SP-1, SE-83, SP-83. (All sold outside the Pacific Northwest.)
8/ Includes rates: J-1, J-2, FE-1, Special, Canadian Treaty, F-8, CE-1, RP-1, RP-2, RP-83, CE-2, CE-83, FE-2.
Includes USBR, Operation & Maintenance, Downstream Benefits, CSPE Transmission, Supplemental Capacity Transmission.
9/ Does not include revenues from Conservation Contract Charges. Numbers may not add to total because of rounding.
10/ 1983 final rate proposal.
11/ Includes rates: PF-1, PF-2, PF-83.
12/ Includes Formula Power Transmission, Integration of Resources, Energy Transmission, Use of Facilities.

Graph 1.c-1

Revenues

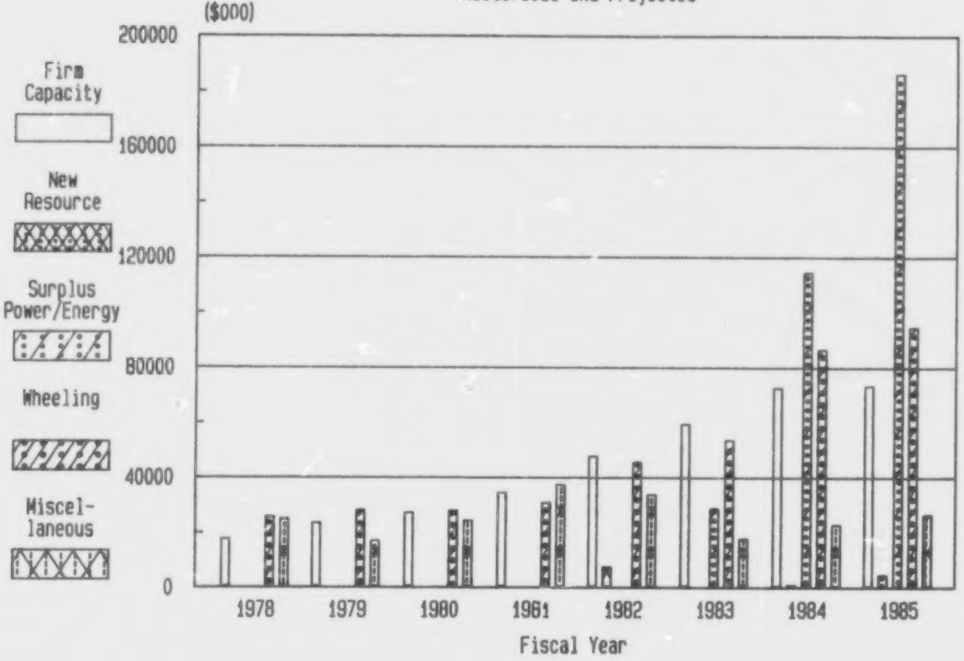
Historical and Projected



Graph 1.c-2

Revenues

Historical and Projected



QUESTION 1.d What were BPA's energy and capacity loads in each rate category during FYs 1978-83? What loads does BPA project in each category for FYs 1984 and 1985? Please plot.

RESPONSE Please see the Tables 1.d-1 and 1.d-2 entitled "Historical and Projected Energy Sales" and "Historical and Projected Capacity Sales" which detail the annual energy loads and peak loads for each of the categories mentioned in question 1.b. MW months are calculated by summing the 12 monthly peak loads of each category over the year. Attached also are bar graphs 1.d-1, 1.d-2 and 1.d-3 depicting the comparative loads for these rate categories.

One cannot reproduce the Revenue Table 1.c-1 by applying the rates in Table 1.b-2 to the loads outlined in Table 1.d-1 and 1.d-2. This is because the average rates provided are weighted on the basis of the months in which the demand and energy charges apply rather than weighted on the basis of sales made or projected at the various energy and demand charges.

FY 1983 Priority Firm sales were lower than preceding years and lower than projected sales for FYs 1984 and 1985 for two main reasons. First, winter temperatures were warmer than normal causing a decrease in space heating demand for electricity; and second, precipitation was above normal providing excess resources for BPA customers to displace purchases from BPA.

FY 1983 Industrial sales were lower than normal because of persisting adverse economic conditions which depressed both demand and prices.

Table 1.d-2

Historical and Projected
Capacity Sales

(Fiscal Year)

Class	1978	1979	1980	1981	1982	1983 9/	1984 9/	1985 9/
Sales (MW Months)								
Priority Firm 1/	64,800	74,172	73,716	76,992	78,612	68,064	73,560	76,908
Residential Exchange 10/	---	---	---	---	34,392	46,908	63,228	72,420
Industrial 2/	36,456	36,684	34,460	37,800	31,260	23,124	31,620	34,836
Nonfirm 3/	0	0	0	0	0	0	0	0
Firm Capacity 4/	10,836	11,124	16,524	15,924	20,832	19,824	20,724	20,724
New Resource 5/	---	---	---	---	2,004	0	0	0
Energy Broker/Displacement 6/	---	---	---	---	---	0	0	0
Surplus Power/Energy 7/	---	---	---	---	---	0	4,644	8,208
Miscellaneous 8/	---	---	---	---	---	---	---	---

Source: Generation and Sales Statistics -- Prepared by Division of Customer Service, Office of Power and Resources Management, Bonneville Power Administration. (All data are detailed in the Documentation to the Sep. 1983 Revenue Forecast Study.)

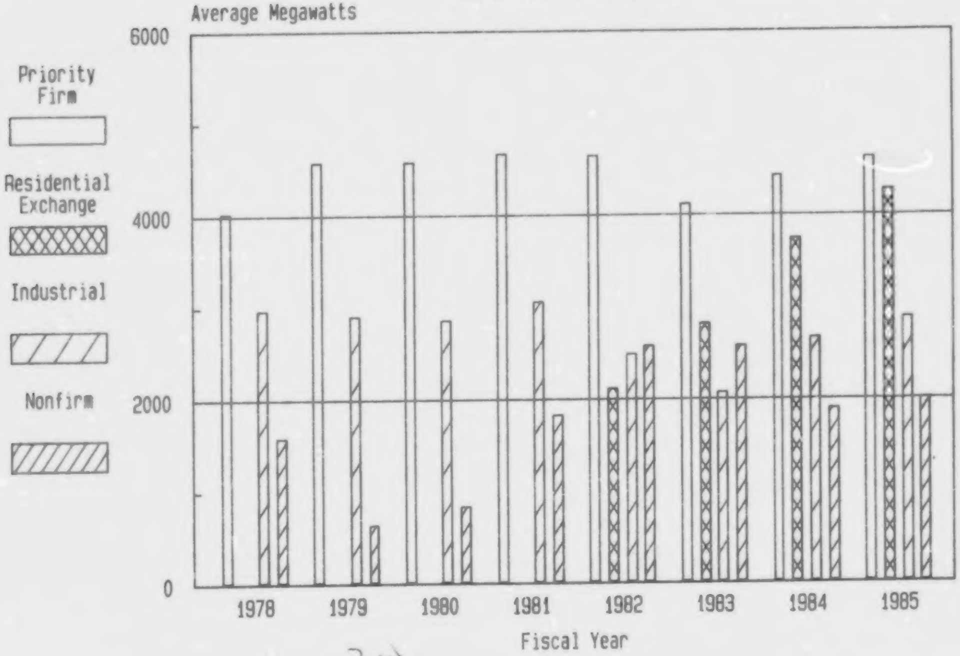
1/ Includes rates: EC-6, EC-7, EC-8, EC-9, PF-1, PF-2, PF-83.
2/ Includes rates: IF-1, IF-2, IP-1, SI-1, IP-2, SI-2 IP-83, IH-83.
3/ Includes rates: N-5, N-6, NF-1, NF-2, NF-83.
4/ Includes rates: F-6, F-7, CF-1, CF-2, CF-83.
5/ Includes rates: NR-1, NR-2, NR-83.
6/ Includes rates: EB-1, Nonfirm Displacement-83.
7/ Includes rates: SE-1, SP-1, SE-83, SP-83. (All sold outside the Pacific Northwest.)
8/ Miscellaneous Capacity Sales are unavailable from historical records.
9/ 1983 final rate proposal.
10/ Includes rates: PF-1, PF-2, PF-83

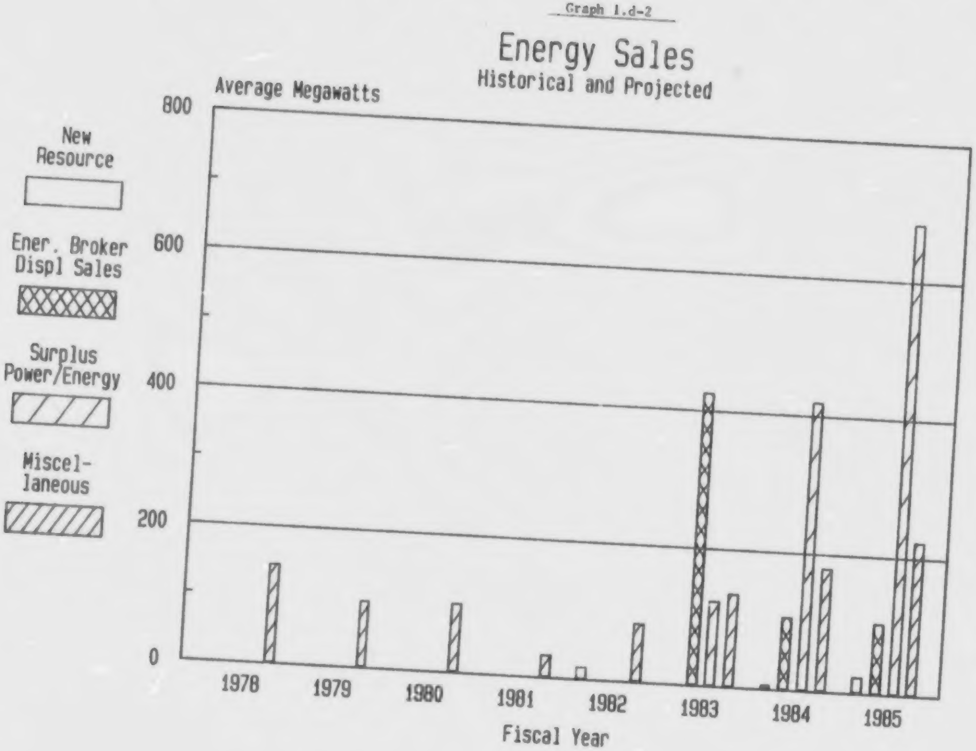
(2156n)

Graph I.d-1

Energy Sales

Historical and Projected





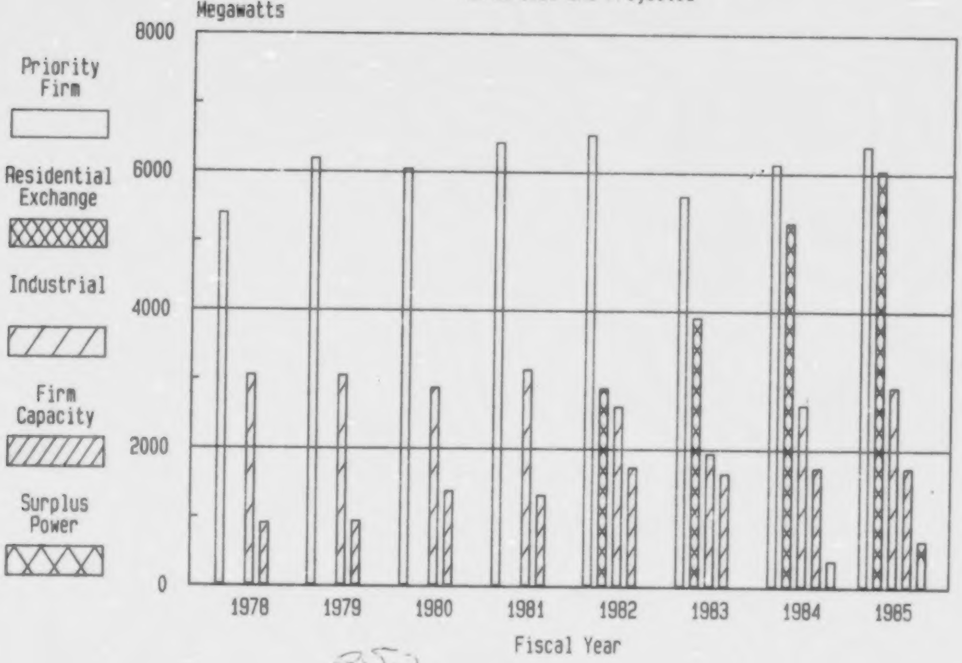
Graph 1.d-2

Energy Sales
Historical and Projected

Graph 1.d-3

Capacity Sales

Historical and Projected



QUESTION 1.e What rates, revenues and loads for each category does BPA project for the years beyond FY 1985? Please provide all such projections BPA has performed. Please plot.

RESPONSE Projected rates through FY 2003 are presented on Table 1.e-1 titled Base Case Wholesale Rate Summary. A graph of this information appears on Graph 1.e-1.

Projected average and peak loads on BPA for Operating Years 1986-88 are presented in subsequent Tables 1.e-2 through 1.e-7 entitled Summary of Loads and Resources of Federal System -- BPA Regional Area -- Federal Table 2. This data has not been graphed because of the amount of detail in the tables furnished.

Residential exchange loads for the investor-owned utilities and Coos-Curry Electric Cooperative through fiscal years 1987-88 are presented in Tables 1.e-8, 1.e-9, and 1.e-10 entitled Residential Exchange Forecast. This data also has not been graphed due to the amount of detail in the Tables.

Tables 1.e-2 through 1.e-10 were included in the documentation submitted to FERC in October 1983 in support of the Loads and Resources Study dated September 30, 1983.

Table 1.e-1

BASE CASE WHOLESALE RATE SUMMARY
(Current Year Dollars)
(mills per kWh)

Fiscal Year	Priority Firm	Industrial Firm	New Resource Firm
1983	18.0	24.5	-- 1/
1984	21.9	25.1	-- 1/
1985	22.8	25.7	-- 1/
1986	24.0	25.7	-- 1/
1987	26.1	25.7	-- 1/
1988	27.5	26.6	33.3
1989	27.4	26.9	36.3
1990	29.5	28.6	42.0
1991	30.0	29.6	44.3
1992	31.2	30.9	46.9
1993	32.3	32.2	49.7
1994	34.6	34.3	52.9
1995	36.4	36.2	56.1
1996	38.2	38.1	59.9
1997	40.1	40.2	65.5
1998	42.8	42.8	73.6
1999	45.4	45.5	86.2
2000	48.9	48.9	99.1
2001	53.4	53.0	114.3
2002	58.0	56.9	131.3
2003	62.5	61.0	148.5

1/ New Resource firm rate not calculated due to no load.

Graph 1.e-1

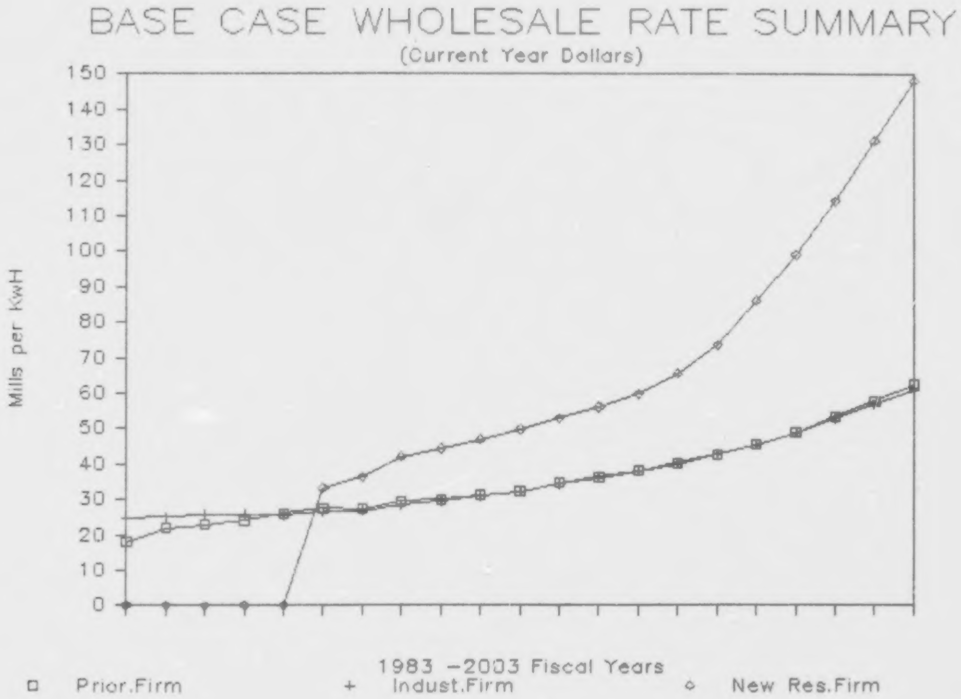

BASE CASE WHOLESALE RATE SUMMARY
(Current Year Dollars)
Mills per KwH
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
1983 –2003 Fiscal Years
□ Prior.Firm
+ Indust.Firm
◇ New Res.Firm

Table 1.e-2

SUMMARY OF LOADS AND RESOURCES OF FEDERAL SYSTEM
BPA REGIONAL AREA

FEDERAL.TABLE2

1985-86 LEVEL

AVERAGE		JUL	AUG 1-15	AUG 16-31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-15	APR 16-30	MAY	JUN	
LOADS																
1 INDUSTRIAL FIRM	1/	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259.0
2 FEDERAL AGENCIES	2/	191	195	195	189	189	190	203	205	203	199	194	194	194	194	196.2
3 USBR RESERVE POWER		195	186	186	123	63	3	2	2	2	2	38	38	133	186	76.2
4 FEDERAL SYSTEM LOSSES		127	130	130	125	133	153	171	179	158	196	161	161	137	130	145.6
5 NON GEN PUBLIC UTIL PURCH		2615	2582	2579	2571	2802	3444	3829	3904	3510	3533	3161	3160	2829	2820	3146.1
6 GEN PUBLIC UTIL PURCHASE	/	1011	1102	1057	1059	1164	1224	1258	1322	1305	1234	1231	1220	1138	1159	1181.2
7 PRIVATE UTILITIES ALLOC.	6/	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30.0
8 LOSSES	9/	47	50	50	50	47	50	54	59	61	56	53	53	52	52	52.6
9 EXPORTS	3/	78	137	137	137	137	137	130	130	130	137	121	121	30	30	112.5
10 CONTRACTS OUT	4/	284	386	386	384	284	284	284	284	284	279	262	262	229	222	289.3
11 C PE TO WEST GROUP UTIL.	7/	666	666	666	664	466	666	666	666	666	666	610	610	610	610	637.9
12 FIRM LOADS		7281	7509	7461	7379	7621	8234	8680	8914	8403	8336	7898	7921	7450	7517	7934.2
13 INDUSTRIAL TOP QUARTILE	11/	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774.0
14 TOP QUARTILE LOSSES	12/	16	17	17	17	16	17	19	20	21	19	18	18	18	18	18.0
15 TOTAL LOADS		8071	8300	8252	8170	8411	9025	9473	9708	9198	9129	8690	8713	8242	8309	8726.2
RESOURCES																
16 SYSTEM HYDRO		6299	5817	5936	6017	6785	7956	8329	8462	7068	7267	7061	7746	12058	7367	7573.5
17 CONTRACT HYDRO	13/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
18 SUS. PRNG. ADJUSTMENT	14/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
19 CAN. ENT. NON-FEDERAL	15/	110	110	110	110	110	110	110	110	110	110	103	103	103	103	108.2
20 RESTORATION	16/	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18.0
21 TOTAL HYDRO		6391	5909	6028	6109	6877	8048	8421	8554	7160	7359	7146	7831	12143	7452	7663.7
22 EX. SM. THRM. & MISC.		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
23 COMB. TURBINES		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
24 HANFORD	17/	0	339	339	339	339	339	339	339	339	339	339	0	0	0	240.1
25 RENEWABLES	18/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
26 COGENERATION		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
27 IMPORTS	19/	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372.0
28 CONTRACTS IN	20/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
29 LARGE THERMAL	21/	1167	1167	1167	275	275	275	1052	1167	1297	1297	1297	1297	1022	1022	943.1
30 TOTAL RESOURCES		7930	7780	7906	7095	7863	9034	10184	10432	9169	9363	9154	9500	13537	8846	9210.9
31 HYD..SM.THRM.& MISC.RES.	22/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
32 LARGE THERMAL RES.	22/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
33 DSI RESERVES	25/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
34 HYDRO MAINTENANCE	26/	-248	-80	-87	-21	-8	-23	-10	0	0	0	-8	-8	-51	-54	-42.9
35 NET RESOURCES		7682	7700	7819	7074	7855	9011	10174	10432	9169	9363	9146	9492	13486	8792	9176.4
36 FIRM SURPLUS OR DEFICIT		400	191	358	-305	234	777	1494	1518	766	1028	1249	1571	6036	1275	1242.2
37 TOTAL SURPLUS OR DEFICIT		-390	-600	-433	-1096	-556	-14	701	724	-29	235	457	779	5244	483	450.3
38 BPA RESOURCE ACQUISITION		2	2	2	2	2	2	2	2	2	2	3	3	3	3	2.2
39 BPA BILLING CREDITS		3	3	0	0	0	0	0	0	0	0	0	0	0	0	0.0
40 FIRM SURPLUS AFTER ACQUIS		402	193	360	-303	236	779	1496	1520	768	1030	1252	1574	6039	1278	1244.9

Table I.e-3
Summary of Loads and Resources of Federal System
BPA REGIONAL AREA

FEDERAL,TABLE2

1985-86 LEVEL

PEAK		JUL	AUG 1-15	AUG 16-31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-15	APR 16-30	MAY	JUN
LOADS															
1 INDUSTRIAL FIRM	1/	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302
2 FEDERAL AGENCIES	2/	287	285	289	283	284	297	303	309	304	300	291	[illegible]	293	293
3 USBR RESERVE POWER		225	224	224	106	83	7	4	4	3	5	104	[illegible]	211	235
4 FEDERAL SYSTEM LOSSES		198	191	191	201	227	269	289	299	263	264	242	242	231	219
5 NON GEN PUBLIC UTIL PURCH		3721	3635	3635	3323	4650	5419	5005	5974	5202	5510	4844	4844	[illegible]	4249
6 GEN PUBLIC UTIL PURCHASE	/	1011	1102	1082	1135	1250	1327	1396	1456	1376	1303	1288	1292	[illegible]	1187
7 PRIVATE UTILITIES ALLOC.	6/	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]	0
8 LOSSES	9/	53	51	51	53	58	67	69	71	67	66	62	62	[illegible]	58
9 EXPORTS	3/	2057	2057	2057	2057	2057	1432	1432	1432	1432	1432	1432	1432	1432	2057
10 CONTRACTS OUT	4/	2123	2123	2123	2123	2123	2123	2123	2123	2123	2123	2096	2096	2096	2096
11 CSPE TO WEST GROUP UTIL.	7/	1134	1134	1134	1134	1134	1134	1134	1134	1134	1134	1093	1093	1093	1093
12 FIRM LOADS		13111	13109	13089	13398	14188	14377	14938	15105	14207	14438	13745	13757	13420	13786
13 INDUSTRIAL TOP QUARTILE	11/	771	771	771	771	771	771	771	771	771	771	771	771	771	771
14 TOP QUARTILE LOSSES	12/	18	17	17	18	19	22	23	24	22	22	21	21	20	19
15 TOTAL LOADS		13900	13897	13877	14187	14978	15170	15732	15900	15000	15231	14537	14549	14211	14576
RESOURCES															
16 SYSTEM HYDRO		20864	20973	21056	21034	21108	21325	21264	21069	21063	21036	20228	20155	19715	20698
17 CONTRACT HYDRO	13/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 SUS. PKNG. ADJUSTMENT	14/	-2959	-2974	-2986	-2931	-2545	-2571	-2564	-2540	-2539	-2536	-2867	-2861	-2795	-2935
19 CAN. ENT. NON-FEDERAL	15/	299	299	299	299	299	299	299	299	299	299	285	285	285	285
20 RESTORATION	16/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 TOTAL HYDRO		18204	18298	18369	18402	18862	19053	18999	18828	18822	18798	17638	17577	17204	18048
22 EX. SM. THRM. & MISC.		0	0	0	0	0	0	0	0	0	0	0	0	0	0
23 COMB. TURBINES		0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 HANFORD	17/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 RENEWABLES	18/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26 COGENERATION		0	0	0	0	0	0	0	0	0	0	0	0	0	0
27 IMPORTS	19/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 CONTRACTS IN	20/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 LARGE THERMAL	21/	1424	1424	1424	324	324	324	1424	1424	1424	1424	1424	1424	1100	1100
30 TOTAL RESOURCES		19628	19722	19793	18726	19186	19377	20423	20252	20246	20282	19062	19001	18304	19148
31 HYD..SM.THML.& MISC.RES.	22/	-1043	-1049	-1093	-1055	-1055	-1066	-1063	-1093	-1093	-1092	-1011	-1008	-986	-1035
32 LARGE THERMAL RES.	22/	-214	-214	-214	-49	-49	-49	-214	-214	-214	-214	-214	-214	-165	-165
33 LSI RESERVES	25/	1257	1262	1266	1183	1184	1115	1277	1267	1267	1269	1229	1221	1151	1200
34 HYDRO MAINTENANCE	26/	-2237	-2499	-2499	-2651	-1756	-1666	-972	-667	-714	-993	-812	-809	-860	-927
35 NET RESOURCES		17391	17224	17296	16079	17431	17711	19451	19565	19532	19229	18250	18196	17464	18221
36 FIRM SURPLUS OR DEFICIT		4280	4115	4284	2678	3244	3333	4513	4460	5325	4791	4505	4439	4044	4437
37 TOTAL SURPLUS OR DEFICIT		3491	3327	3418	1889	2454	2540	3719	3665	4532	3998	3713	3647	3253	3647
38 BPA RESOURCE ACQUISITION		2	2	2	2	2	2	2	2	2	2	3	3	3	3
39 BPA BILLING CREDITS		0	0	0	0	0	0	0	0	0	0	0	0	0	0
40 FIRM SURPLUS AFTER ACQUIS		4282	4117	4286	2680	3246	3335	4515	4462	5327	4793	4508	4442	4047	4440
41 TOTAL SURPLUS AFTER ACQUIS		3493	3329	3420	1891	2456	2542	3721	3667	4534	4000	3716	3650	3256	3650

Table I.e-4

SUMMARY OF LOADS AND RESOURCES OF FEDERAL SYSTEM
BPA REGIONAL AREA

FEDERAL,TABLE7

1986-87 LEVEL

AVERAGE		JUL	AUG 1-15	AUG 16-31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-15	APR 16-30	MAY	JUN	
LOADS																
1 INDUSTRIAL FIRM	1/	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259.0
2 FEDERAL AGENCIES	2/	193	198	198	191	197	201	206	208	206	202	197	197	251	237	206.0
3 USBR RESERVE POWER		215	205	205	136	46	3	2	2	2	2	38	38	193	187	88.9
4 FEDERAL SYSTEM LOSSES		130	131	133	127	136	156	176	183	161	195	146	146	140	140	148.2
5 NON GEN PUBLIC UTIL PURCH		2697	2654	2653	2648	2980	3537	3910	4079	3501	3519	3231	3244	2912	2887	3218.4
6 GEN PUBLIC UTIL PURCHASE	/	1083	1069	1039	1050	1154	1210	1250	1309	1306	1281	1162	1188	1129	1118	1165.5
7 PRIVATE UTILITIES ALLOC.	6/	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50.0
8 LOSSES	9/	47	50	50	50	47	50	54	59	61	56	53	53	57	52	52.6
9 EXPORTS	3/	78	137	137	137	137	137	138	138	138	137	121	121	30	30	112.5
10 CONTRACTS OUT	4/	284	306	306	304	284	284	284	284	284	279	262	262	229	222	289.3
11 CSPE TO WEST GROUP UTIL.	7/	418	418	418	418	418	418	418	418	418	418	393	393	393	393	411.7
12 FIRM LOADS		7375	7567	7537	7459	7692	8322	8761	8997	8475	8296	7919	7957	7586	7584	8003.1
13 INDUSTRIAL TOP QUARTILE	11/	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774.0
14 TOP QUARTILE LOSSES	12/	16	17	17	17	16	17	19	20	21	19	18	18	18	18	18.0
15 TOTAL LOADS		8165	8358	8328	8258	8482	9113	9554	9791	9270	[illegible]	8711	8749	8378	8376	8795.1
RESOURCES																
16 SYSTEM HYDRO		6645	6882	6885	6466	7163	7382	8071	8310	7339	6921	6972	7320	11978	7134	7620.0
17 CONTRACT HYDRO	13/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
18 SUS. PKNG. ADJUSTMENT	14/	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
19 CAN. ENT. NON-FEDERAL	15/	103	103	103	103	103	103	103	103	103	103	96	96	96	96	100.7
20 RESTORATION	16/	-10	-10	-10	-10	-10	-10	-10	-10	-10	-20	-10	-10	-10	-10	-10.0
21 TOTAL HYDRO		6730	6967	6970	6559	7248	7467	8156	8395	7424	7006	7048	7404	12054	7210	7703.9
22 EX. SM. THRM. & MISC.		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
23 COMB. TURBINES		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
24 HANFORD	17/	0	339	339	339	339	339	339	339	339	339	339	0	0	0	240.1
25 RENEWABLES	18/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
26 COGENERATION		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
27 IMPORTS	19/	309	222	222	222	222	222	221	207	207	207	207	207	197	195	219.0
28 CONTRACTS IN	20/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
29 LARGE THERMAL	21/	1297	275	275	275	341	1297	1297	1297	1297	1297	1297	1297	1022	1022	1001.9
30 TOTAL RESOURCES		8336	7804	7806	7395	8151	9325	10014	10230	9267	8849	8891	8908	13273	8427	9169.0
31 HYD..SM.THML.& MISC.RES.	22/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
32 LARGE THERMAL RES.	22/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
33 DSI RESERVES	25/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
34 HYDRO MAINTENANCE	26/	-272	-94	-92	-20	-8	-23	-10	0	0	0	-8	-8	-48	-52	-44.4
35 NET RESOURCES		8064	7710	7714	7375	8143	9303	10004	10230	9267	8849	8884	8900	13225	8375	9120.5
36 FIRM SURPLUS OR DEFICIT		689	143	177	-84	451	981	1243	1241	792	553	965	943	[illegible]	791	1117.5
37 TOTAL SURPLUS OR DEFICIT		-101	-648	-614	-875	-339	190	450	447	-3	-240	173	151	4847	-1	325.5
38 BPA RESOURCE ACQUISTION		3	3	3	3	3	3	3	3	3	3	5	5	5	5	3.5
39 BPA BILLING CREDITS		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
40 FIRM SURPLUS AFTER ACQUIS		692	146	180	-81	454	984	1246	1244	795	556	970	948	5644	796	1121.0
41 TOTAL SURPLUS AFTER ACQUIS		-98	-645	-611	-872	-336	193	453	450	-0	-237	178	156	4852	4	329.0

Table 1.e-5

SUMMARY OF LOADS AND RESOURCES OF FEDERAL SYSTEM
BPA REGIONAL AREA

FEDERAL.TABLE7

1986-87 LEVEL

PEAK		JUL	AUG 1-15	AUG 16-31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-15	APR 16-30	MAY	JUN
LOADS															
1 INDUSTRIAL FIRM	1/	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302
2 FEDERAL AGENCIES	2/	292	296	296	287	291	302	300	314	307	303	296	296	296	296
3 USBR RESERVE POWER		267	266	266	285	92	7	4	6	3	5	104	104	211	235
4 FEDERAL SYSTEM LOSSES		205	198	198	209	235	270	290	307	270	271	249	269	230	226
5 NON GEN PUBLIC UTIL PURCH		3850	3707	3707	4076	4970	5005	6004	6182	5336	5654	4970	4970	4646	4366
6 GEN PUBLIC UTIL PURCHASE	/	1036	1006	1088	1198	1263	1334	1400	1469	1396	1700	1210	1767	1201	1160
7 PRIVATE UTILITIES ALLOC.	6/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 LOSSES	9/	53	51	51	53	58	67	69	71	67	64	62	62	60	58
9 EXPORTS	3/	2057	1510	1510	1510	1510	565	805	830	830	830	830	830	706	1411
10 CONTRACTS OUT	4/	2096	2096	2096	2096	2096	2096	2096	2096	2096	2096	2075	2075	2075	2075
11 CSPE TO WEST GROUP UTIL.	7/	1093	1093	1093	1093	1093	1093	1093	1093	1093	1093	1052	1052	1052	1052
12 FIRM LOADS		13239	12661	12663	13028	13760	13969	14527	14618	13700	13907	13150	13207	12867	13181
13 INDUSTRIAL TOP QUARTILE	11/	771	771	771	771	771	771	771	771	771	771	771	771	771	771
14 TOP QUARTILE LOSSES	12/	18	17	17	18	19	22	25	24	22	22	21	21	20	19
15 TOTAL LOADS		14028	13449	13451	13817	14558	14762	15321	15413	14493	14700	13942	13999	13658	13971
RESOURCES															
16 SYSTEM HYDRO		20840	20931	21009	21059	21005	21261	21091	20956	20782	20505	19057	19065	19458	20794
17 CONTRACT HYDRO	13/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 SUS. PKNG. ADJUSTMENT	14/	-2959	-2968	-2979	-2986	-2533	-2581	-2563	-2927	-2496	-2402	-2016	-2031	-2759	-2949
19 CAN. ENT. NON-FEDERAL	15/	289	285	285	285	289	285	289	285	205	205	274	274	274	274
20 RESTORATION	16/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 TOTAL HYDRO		18170	18248	18315	18358	18757	18965	18833	18715	18491	18309	17316	17307	16973	18119
22 EX. SM. THRM. & MISC.		0	0	0	0	0	0	0	0	0	0	0	0	0	0
23 COMB. TURBINES		0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 HANFORD	17/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 RENEWABLES	18/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26 COGENERATION		0	0	0	0	0	0	0	0	0	0	0	0	0	0
27 IMPORTS	19/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 CONTRACTS IN	20/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 LARGE THERMAL	21/	1624	324	324	324	324	1624	1624	1624	1624	1624	1624	1624	1108	1108
30 TOTAL RESOURCES		19594	18572	18639	18682	19081	20589	20257	20339	20115	19933	18940	18931	18073	19219
31 HYD.,SM.THML.& MISC.RES.	21/	-1042	-1047	-1050	-1053	-1058	-1062	-1055	-1040	-1035	-1029	-993	-997	-973	-1040
32 LARGE THERMAL RES.	22/	-214	-49	-49	-49	-49	-214	-214	-214	-214	-214	-214	-214	-165	-165
33 DSI RESERVES	25/	1256	1095	1099	1182	1099	1276	1268	1261	1249	1243	1286	1211	1130	1205
34 HYDRO MAINTENANCE	26/	-2237	-2499	-2499	-2650	-1796	-1865	-971	-666	-710	-902	-886	-883	-827	-926
35 NET RESOURCES		17356	16073	16140	16032	17327	18724	19286	19673	19205	18830	17936	18068	17246	18293
36 FIRM SURPLUS OR DEFICIT		4117	3412	3477	3003	3559	4755	4759	5054	5505	4924	4783	4861	4379	5113
37 TOTAL SURPLUS OR DEFICIT		3328	2624	2689	2214	2769	3962	3965	4859	4712	4131	3991	4069	3588	4323
38 BPA RESOURCE ACQUISTION		3	3	3	3	3	3	3	3	3	3	5	5	5	5
39 BPA BILLING CREDITS		0	0	0	0	0	0	0	0	0	0	0	0	0	0
40 FIRM SURPLUS AFTER ACQUIS		4120	3415	3480	3006	3562	4758	4762	5057	5508	4927	4788	4866	4384	5118
41 TOTAL SURPLUS AFTER ACQUIS		3331	2627	2692	2217	2772	3965	3968	4862	4715	4134	3996	4074	3593	4328

Table 1. e-6

SUMMARY OF LOADS AND RESOURCES OF FEDERAL SYSTEM
BPA REGIONAL AREA

FEDERAL.TABLE7

1987-88 LEVEL

AVERAGE		JUL	AUG 1-15	AUG 16-31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-15	APR 16-30	MAY	JUN	
LOADS																
1 INDUSTRIAL FIRM	1/	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259	2259.0
2 FEDERAL AGENCIES	2/	196	201	201	194	195	204	209	212	209	205	100	100	200	200	193.7
3 USBR RESERVE POWER		215	285	285	136	46	3	2	2	2	2	38	38	133	187	80.9
4 FEDERAL SYSTEM LOSSES		135	137	137	132	140	161	179	188	166	162	160	160	144	144	152.9
5 NON GEN PUBLIC UTIL PURCH		2784	2728	2723	2698	3027	3606	3903	4142	3637	3604	3260	3266	2951	2980	3206.3
6 GEN PUBLIC UTIL PURCHASE	/	931	1086	972	999	1086	1110	1100	1214	1212	1112	1071	1055	1067	986	1071.9
7 PRIVATE UTILITIES ALLOC.	6/	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68.0
8 LOSSES	9/	47	58	58	58	67	59	54	59	61	56	53	53	52	52	52.6
9 EXPORTS	3/	78	125	125	125	125	125	126	126	126	125	125	125	76	76	112.2
10 CONTRACTS OUT	4/	284	306	306	304	284	286	284	284	284	279	262	262	229	222	289.3
11 CSPE TO WEST GROUP UTIL.	7/	393	393	393	393	393	393	393	393	393	393	368	368	368	368	386.7
12 FIRM LOADS		7383	7558	7519	7438	7671	8271	8658	8967	8418	8345	7760	7742	7525	7469	7951.2
13 INDUSTRIAL TOP QUARTILE	11/	776	776	776	776	776	776	776	776	776	776	776	776	776	776	776.0
14 TOP QUARTILE LOSSES	12/	16	17	17	17	16	17	19	20	21	19	18	18	18	18	18.0
15 TOTAL LOADS		8173	8349	8310	8229	8461	9062	9451	9761	9213	9138	8552	8534	8317	8261	8743.2
RESOURCES																
16 SYSTEM HYDRO		6157	6002	6563	6377	6810	7699	8609	8926	7186	8273	10021	13461	12861	12615	8661.4
17 CONTRACT HYDRO	13/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
18 SUS. PKNG. ADJUSTMENT	14/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
19 CAN. ENT. NON-FEDERAL	15/	94	94	94	94	94	94	94	94	94	94	87	87	87	87	92.2
20 RESTORATION	16/	-18	-18	-18	-18	-18	-18	-19	-18	-18	-18	-18	-18	-18	-18	-18.0
21 TOTAL HYDRO		6233	6078	6639	6453	6886	7775	8685	9002	7262	8349	10090	13530	12930	12684	8735.6
22 EX. SM. THRM. & MISC.		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
23 COMB. TURBINES		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
24 HANFORD	17/	0	339	339	339	339	339	339	339	339	339	339	0	0	0	240.1
25 RENEWABLES	18/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
26 COGENERATION		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
27 IMPORTS	19/	190	38	38	38	38	38	38	36	29	29	29	29	29	29	46.7
28 CONTRACTS IN	20/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
29 LARGE THERMAL	21/	1297	275	275	275	341	1297	1297	1297	1297	1297	1297	1297	1022	1022	1001.5
30 TOTAL RESOURCES		7720	6730	7291	7106	7604	9449	10360	10695	8927	10015	12556	14856	13981	13735	10024.0
31 HYD.,SM.THRL.& MISC.RES.	22/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
32 LARGE THERMAL RES.	22/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
33 DSI RESERVES	25/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
34 HYDRO MAINTENANCE	26/	-254	-87	-84	-22	-8	-21	-10	0	0	0	-8	-8	-54	-54	-43.1
35 NET RESOURCES		7466	6643	7207	7084	7596	9428	10350	10695	8927	10015	12547	14848	13927	13681	9980.9
36 FIRM SURPLUS OR DEFICIT		83	-915	-312	-355	-75	1157	1692	1728	510	1670	4787	7106	6402	6212	2029.7
37 TOTAL SURPLUS OR DEFICIT		-707	-1706	-1103	-1146	-865	366	899	934	-285	877	3995	6314	5610	5420	1237.7
38 BPA RESOURCE ACQUISITION		5	5	5	5	174	174	174	174	174	174	174	174	174	174	131.7
39 BPA BILLING CREDITS		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
40 FIRM SURPLUS AFTER ADJUSTS.		88	-910	-307	-350	99	1331	1866	1902	684	1844	4961	7280	6576	6386	2161.5

Table 1.e-7
SUMMARY OF LOADS AND RESOURCES OF FEDERAL SYSTEM
BPA REGIONAL AREA

FEDERAL.TABLE2

1987-88 LEVEL

PEAK		JUL	AUG 1-15	AUG 16-31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-15	APR 16-30	MAY	JUN
LOADS															
1 INDUSTRIAL FIRM	1/	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302	2302
2 FEDERAL AGENCIES	2/	296	298	298	291	295	306	312	318	312	308	299	299	301	300
3 USBP RESERVE POWER		247	244	244	205	92	7	4	4	3	5	184	184	211	235
4 FEDERAL SYSTEM LOSSES		211	205	205	215	242	286	306	315	277	270	259	255	244	232
5 NON GEN PUBLIC UTIL PURCH		3976	3900	3900	4176	4947	5743	6197	6259	5443	5761	5116	5069	4736	4399
6 GEN PUBLIC UTIL PURCHASE	/	958	1035	1032	1095	1199	1277	1403	1549	1418	1344	1172	1173	1148	1028
7 PRIVATE UTILITIES ALLOC.	6/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 LOSSES	9/	53	51	51	53	58	67	69	71	67	66	62	62	60	58
9 EXPORTS	3/	1411	213	213	213	213	213	213	213	188	188	188	188	188	188
10 CONTRACTS OUT	4/	2075	2075	2075	2075	2075	2075	2075	2075	2075	2075	2058	2058	2058	2058
11 CSPE TO WEST GROUP UTIL.	7/	1052	1052	1052	1052	1052	1052	1052	1052	1052	1052	1012	1012	1012	1012
12 FIRM LOADS		12581	11375	11372	11677	12476	13327	13933	14158	13121	13369	12552	12503	12238	11787
13 INDUSTRIAL TOP QUARTILE	11/	771	771	771	771	771	771	771	771	771	771	771	771	771	771
14 TOP QUARTILE LOSSES	12/	18	17	17	18	19	22	23	24	22	22	21	21	20	19
15 TOTAL LOADS		13370	12163	12160	12466	13264	14120	14727	14953	13914	14162	13344	13295	13029	12577
RESOURCES															
16 SYSTEM HYDRO		20635	20085	20131	20488	20629	20745	20468	19803	18911	18434	18217	18249	18631	20669
17 CONTRACT HYDRO	13/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 SUS. PKNG. ADJUSTMENT	14/	-2926	-2848	-2855	-2906	-2487	-2501	-2468	-2387	-2288	-2222	-2383	-2587	-2642	-2931
19 CAN. ENT. NON-FEDERAL	15/	274	274	274	274	274	274	274	274	274	274	261	261	261	261
20 RESTORATION	16/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 TOTAL HYDRO		17983	17511	17551	17856	18416	18518	18274	17689	16905	16486	16095	15923	16250	17999
22 EX. SM. THRM. & MISC.		0	0	0	0	0	0	0	0	0	0	0	0	0	0
23 COMB. TURBINES		0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 HANFORD	17/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 RENEWABLES	18/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26 COGENERATION		0	0	0	0	0	0	0	0	0	0	0	0	0	0
27 IMPORTS	19/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 CONTRACTS IN	20/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 LARGE THERMAL	21/	1424	324	324	324	324	1424	1424	1424	1424	1424	1424	1424	1100	1100
30 TOTAL RESOURCES		19407	17835	17875	18180	18740	19942	19698	19113	18329	17910	17519	17347	17350	19099
31 HYD.,SM.THRML.& MISC.RES.	22/	-1032	-1004	-1007	-1024	-1031	-1037	-1023	-990	-946	-922	-911	-912	-932	-1033
32 LARGE THERMAL RES.	22/	-214	-49	-49	-49	-49	-214	-214	-214	-214	-214	-214	-214	-159	-159
33 DSI RESERVES	25/	1245	1053	1055	1073	1080	1791	1237	1204	1159	1135	1126	1126	1097	1190
34 HYDRO MAINTENANCE	26/	-2237	-2499	-2499	-2651	-1796	-1066	-971	-866	-712	-989	-815	-816	-860	-920
35 NET RESOURCES		17169	15337	15375	15530	16987	18276	18727	18448	17617	16921	16504	16530	16503	18171
36 FIRM SURPLUS OR DEFICIT		4588	3962	4003	3853	4511	4949	4794	4290	4496	3551	3952	4028	4269	6384
37 TOTAL SURPLUS OR DEFICIT		3799	3174	3215	3064	3723	4156	4000	3495	3703	2759	3160	3235	3474	5594
38 BPA RESOURCE ACQUISITION		5	5	5	5	176	176	176	176	176	176	176	176	176	176
39 BPA BILLING CREDITS		3	2	1	0	0	0	0	0	0	0	0	0	0	0
40 FIRM SURPLUS AFTER ACQUIS		4596	3969	4009	3858	4687	5125	4970	4466	4672	3727	4128	4204	4445	6560

Table 1.e-8

~~Table III~~

RESIDENTIAL EXCHANGE FORECAST 1/

FY-1986

Line No.	Utility	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Fiscal Year 1986 Average
	MPC													
1.	Avg. MW	60	67	89	93	96	86	74	66	67	66	65	66	74.52
2.	Peak	76	84	112	118	121	108	93	83	84	83	83	84	93.92
	PPL													
3.	Avg. MW	693	884	1088	1256	1286	996	976	815	775	714	755	756	916.26
4.	Peak	924	1179	1471	1698	1738	1345	1319	1102	1034	952	1007	1008	1231.33
	PGE													
5.	Avg. MW	585	760	917	1017	1118	894	824	664	613	548	531	558	752.41
6.	Peak	808	1040	1304	1478	1469	1272	1171	952	844	742	731	768	1048.75
	PSPL													
7.	Avg. MW	841	997	1188	1448	1576	1361	1215	1039	882	730	681	729	1057.33
8.	Peak	1204	1427	1755	2139	2327	2011	1794	1535	1262	1045	974	1043	1542.92
	UPL													
9.	Avg. MW	93	64	82	97	105	82	79	68	152	259	213	124	118.11
10.	Peak	123	85	103	121	131	103	100	85	201	342	282	164	153.42
	CPN													
11.	Avg. MW	30	31	38	42	49	39	35	31	33	31	33	35	35.58
12.	Peak	43	44	56	62	72	57	52	45	47	45	48	51	51.92
	CCEC													
13.	Avg. MW	13	16	22	26	27	23	21	18	15	13	12	13	18.25
14.	Peak	22	28	37	44	45	38	36	31	26	22	20	23	31.00
	IPCO													
15.	Avg. MW	553	402	493	565	624	515	456	604	844	1046	1008	854	663.74
16.	Peak	746	542	653	749	826	682	605	800	1137	1410	1358	1151	888.25
	WWP													
17.	Avg. MW	298	411	535	533	559	448	393	318	283	270	269	278	382.84
18.	Peak	412	570	738	735	771	617	542	438	392	374	373	385	528.92
	TOTALS													
19.	Avg. MW	3167	3633	4452	5078	5439	4443	4075	3623	3665	3676	3567	3413	4019.00
20.	Peak	4358	5005	6228	7144	7500	6232	5713	5071	5028	5015	4875	4676	5570.00

1/ Numbers may not add due to rounding

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Table 1.e-9

RESIDENTIAL EXCHANGE FORECAST 1/
FY-1987

Line No.	Utility	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Fiscal Year 1987 Average
	MPC													
1.	Avg. MW	66	73	97	102	105	94	81	72	73	72	72	73	81.76
2.	Peak	83	92	122	129	132	118	102	91	93	91	91	92	103.00
	PPL													
3.	Avg. MW	698	892	1102	1276	1305	1011	992	827	787	728	767	767	929.03
4.	Peak	931	1190	1489	1724	1764	1366	1341	1118	1049	965	1023	1022	1248.50
	PGE													
5.	Avg. MW	593	768	921	1126	1290	945	868	724	661	591	582	661	806.67
6.	Peak	817	1058	1309	1602	1835	1344	1235	1031	910	815	801	842	1133.25
	PSPL													
7.	Avg. MW	865	1025	1221	1488	1620	1399	1247	1069	907	751	700	749	1086.81
8.	Peak	1238	1467	1804	2199	2392	2067	1842	1578	1298	1074	1001	1072	1586.00
	UPL													
9.	Avg. MW	97	66	81	97	106	83	80	69	158	267	220	128	121.00
10.	Peak	128	88	102	122	133	104	100	86	209	353	291	170	157.17
	CPN													
11.	Avg. MW	30	31	39	43	50	39	36	31	33	31	33	36	35.94
12.	Peak	44	45	57	63	73	58	52	45	48	45	48	52	52.50
	CCEC													
13.	Avg. MW	14	17	22	27	28	24	22	19	16	13	12	14	18.94
14.	Peak	23	29	38	45	47	40	38	32	27	23	21	24	32.25
	IPCO													
15.	Avg. MW	569	415	508	584	645	532	472	623	868	1076	1037	879	683.98
16.	Peak	767	559	673	773	854	704	625	825	1170	1450	1397	1185	915.33
	WWP													
17.	Avg. MW	305	422	547	548	572	460	403	326	290	275	275	283	392.15
18.	Peak	422	584	754	756	789	635	556	449	401	382	381	392	541.75
	TOTALS													
19.	Avg. MW	3238	3710	4538	5291	5720	4587	4201	3740	3793	3800	3697	3590	4156.00
20.	Peak	4454	5112	6349	7413	8019	6436	5892	5257	5205	5198	5054	4850	5770.00

1/ Numbers may not add due to rounding

(WP-PKSB-4486B)5

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Table 1.e-10

Table III

RESIDENTIAL EXCHANGE FORECAST 1/

FY-1988

Line No.	Utility	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Fiscal Year 1988 Average
	MPC													
1.	Avg. MW	68	75	100	106	108	97	84	75	76	75	74	75	84.40
2.	Peak	86	95	126	133	137	122	105	94	96	94	93	95	106.33
	PPL													
3.	Avg. MW	708	907	1124	1297	1326	1039	1008	840	798	734	778	777	944.69
4.	Peak	944	1210	1518	1753	1792	1404	1362	1135	1064	979	1038	1036	1269.58
	PGE													
5.	Avg. MW	640	799	773	1157	1260	970	894	742	681	609	599	618	828.08
6.	Peak	880	1100	1384	1638	1792	1380	1272	1056	938	839	825	854	1163.17
	PSPL													
7.	Avg. MW	889	1054	1255	1530	1665	1443	1284	1098	932	772	719	770	1117.64
8.	Peak	1272	1508	1854	2260	2459	2131	1896	1623	1334	1104	1029	1102	1631.00
	UPL													
9.	Avg. MW	100	68	84	100	109	85	82	71	166	275	227	132	125.03
10.	Peak	132	91	105	126	137	107	103	89	219	364	300	175	162.42
	CPN													
11.	Avg. MW	31	31	40	43	51	40	36	31	33	31	33	36	36.40
12.	Peak	45	45	59	64	74	58	53	46	48	45	48	52	53.17
	CCEC													
13.	Avg. MW	14	18	23	28	29	24	23	20	16	14	13	14	19.65
14.	Peak	24	30	39	47	49	41	39	33	28	23	22	24	33.42
	IPCO													
15.	Avg. MW	587	429	527	605	668	551	489	642	893	1106	1066	905	705.72
16.	Peak	791	579	698	801	884	729	648	851	1204	1491	1437	1220	944.33
	WWP													
17.	Avg. MW	312	433	561	563	595	473	413	333	297	281	280	289	402.64
18.	Peak	433	599	774	777	821	652	570	460	411	390	388	401	556.25
	TOTALS													
19.	Avg. MW	3350	3815	4688	5425	5810	4722	4313	3852	3893	3897	3790	3618	4264.00
20.	Peak	4608	5257	6559	7599	8145	6626	6048	5385	5342	5329	5180	4958	5919.00

1/ Numbers may not add due to rounding

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2. BPA'S REPAYMENT TO THE U.S. TREASURY

QUESTION 2.a How much cumulative principal has BPA repaid to the Treasury at the close of FY 1983? How much principal does BPA plan to repay during FY 1984? FY 1985?

RESPONSE By the close of FY 1983, BPA had repaid the Treasury interest and principal of about $3.1 billion. Of this amount, $638.3 million is principal. BPA in its recent rate case designed its proposed rates to make deferral payments of $153.4 million in FY 1984 and an $82.5 million payment in FY 1985, as well as a $225.9 million principal payment in FY 1985. In addition, BPA anticipates paying the Treasury for interest of $366.8 million in FY 1984 and $405.7 million in FY 1985. Under current repayment provisions, these amounts would make BPA totally current in all of its Treasury payments.

QUESTION 2.b If BPA had been required to repay federal investment on a fixed, mortgage-type amortization schedule--

(1) How much principal should BPA have repaid to the Treasury by the close of FY 1983?
(2) How much principal should BPA pay during FY 1984? FY 1985?

RESPONSE With the combination of poor water conditions, fixed contracts, and severe economic recessions and BPA's inability to borrow to pay for operating expenses, BPA could not have maintained a fixed repayment schedule during the past decade unless it deferred additional amounts to the Treasury. If BPA had been required to repay Federal investment on a fixed mortgage-type amortization schedule over the current amortization life of plant investment (20 years for conservation, 35 years for the transmission system, and 50 years for the generation projects), BPA through the end of FY 1983 would have been scheduled to repay about $4.0 billion to the Treasury for interest and principal. Of this amount, $1,432.9 million would have been principal payments. If, however, BPA had been required to repay Federal investment on a fixed mortgage-type amortization schedule over the average useful life of plant investment (20 years for conservation, 35 years for the transmission system, and 85 years for the generation projects), BPA through the end of FY 1983 would have been scheduled to repay about $3.7 billion to the Treasury for interest and principal. Of this amount, $894.5 million would have been principal payments.

If in FY 1984 BPA adopted a fixed mortgage-type amortization schedule over the average useful life of plant investment, BPA's scheduled principal payments would be $182.5 million--$89.6 million in FY 1984 and $92.9 million in FY 1985. If in FY 1984 BPA adopted a fixed mortgage-type amortization schedule over the current amortization life of plant investment, BPA's scheduled principal payments would be $292.6 million--$143.6 million in FY 1984 and $149.0 million in FY 1985.

QUESTION 2.c If BPA were to treat debt service on WPPSS 1, 2, & 3 prior to operation of the plants as an investor-owned utility treats AFUDC--

(1) How much would that treatment lower BPA's revenue requirements since FY 1977?
(2) How much would that treatment lower BPA's revenue requirements for FY 1984? FY 1985?

RESPONSE The Supply System capitalized accrued interest expense until it was precluded by net-billed contract stipulations. These stipulations established specific dates (referred to as the date certain) when the Supply System could no longer borrow for the cost of servicing existing debt for an individual project. The dates certain for Supply System WNP-1 was September 1, 1980; for WNP-2, September 1, 1977; and for WNP-3, September 1, 1981. On the date certain BPA became committed to paying the Supply System's interest expense for that individual net-billed project.

When it became apparent that the commercial operation date and the date certain for the net-billed projects would not coincide, BPA had the following two options:

- BPA could make payments under the net-billing agreements to fund the Supply System net-billed project's debt-service costs during construction.
- The Supply System could issue bonds for paying such debt service. These bonds would have had to be made expressly subordinate to the construction bonds issued under the project bond resolutions.

In early 1979 BPA conducted an analysis which showed that a Supply System subordinate funding program would have reduced revenue requirements prior to the commercial operation of the Supply System net-billed projects, and would have lead to a moderate increase in BPA's revenue requirements thereafter.

BPA initiated discussions with the participating utilities and the Supply System regarding a program to issue subordinate bonds to fund these costs during construction after the date certain. A unanimous decision on the part of the 104 participating utilities was necessary to issue subordinate bonds. Two utilites did not consent to such a change. Therefore, BPA is recovering the debt-service costs of the Supply System net-billed project bonds through BPA rates.

Funding the Supply System net-billed projects' debt-service costs through rates has proven to be the more prudent alternative. If the Supply System could have issued subordinate bonds to fund debt-service costs prior to commercial operation, it may have lost access to the bond market earlier than its last bond sale in 1982. Such subordinated bonds may have served only to exacerbate Supply System financing difficulties.

While borrowing to pay the Supply System debt-service costs may have lowered the revenue requirements between FY 1977 and FY 1983, this policy would have had a tremendous impact upon the revenue requirements of FY 1984 and FY 1985 due the Supply System's loss of access to the bond market. BPA's near-term ratepayers would have had to pay for the ongoing Supply System costs in the revenue requirements for those years, as well as the additional debt-service costs of the increased borrowing used to pay for the interest accrued between FY 1977 and FY 1982.

Between FY 1977 and FY 1983 BPA has paid almost $1.5 billion for the debt-service costs of the Supply System. To determine the actual impact upon BPA's historic revenue requirements of treating this amount as AFUDC would require an extensive analysis. To fully analyze the future impact of incurring this large amount of additional debt specific assumptions about the timing, the length, the terms, and the interest rate associated with such borrowing would have to be made. To fully answer this question it will be necessary for our staffs to work together to determine the appropriate assumptions.

3. BPA 1983 RATE ADJUSTMENTS

QUESTION 3.a What was BPA's cumulative interest deferral at the close of FY 1983?

RESPONSE The cumulative interest deferral as of September 30, 1983, is estimated at $217.5 million. The estimate consists of the $152.2 million cumulative interest deferral as of September 30, 1982, and FY 1983 interest deferral estimate of $65.3 million. Again, the FY 1983 data are based on initial year end information prior to reclassification and audit adjustments.

QUESTION 3.b What actions has BPA taken to reduce the probability of additional interest deferrals during FY 1984 and FY 1985?

RESPONSE The rates BPA plans to implement on November 1, 1983, reflect an acceleration of its planned amortization payments during the rate period. Prior to 1982, the repayment method employed was designed to produce relatively constant annual payments to the Treasury for the sum of interest, deferral, and amortization of Federal investment. However, given the size of BPA's current deferral, this approach would result in very small amortization payments. BPA's new policy calls for increased payments to the Treasury until the cumulative deferral is paid. Under the new policy, BPA plans to pay the Treasury $462 million for deferral and amortization for FY 1984 and 1985. This amount would have been only $253 million using BPA's original repayment method.

BPA has taken several additional steps to enhance its ability to meet its repayment commitment including (1) use of more sophisticated load forecasting techniques, (2) financing a portion (5 percent) of capital investment through rate revenues in accordance with standard utility practice, which will not require legislative change, (3) development of automatic adjustment clauses to respond to unanticipated changes in Supply System costs and the cost of the residential exchange program, (4) application of a customer charge and offer of an incentive rate for direct-service industrial customers which will help to stabilize loads, (5) adoption of changed billing determinates which will better reflect the cost to serve customers with computed requirements, and (6) development of Surplus Firm Power and Nonfirm Energy rate schedules which allow increased marketing flexibility.

BPA believes it has adopted realistic, conservative revenue forecasts of sales to the DSI's, surplus firm power sales, and nonfirm energy sales. The DSI load forecast is based on a model which reflects the economics of all operating aluminum plants in the region. The results of modeling current aluminum price forecasts were averaged, using an 85 percent to 15 percent weighting, assuming a low price of aluminum throughout the rate period.

In forecasting nonfirm sales and revenues, competition from PNW utilities and from BC Hydro is explicitly modeled. When BPA is selling at the Standard rate it is assumed that all PNW utilities, including BC Hydro, will sell their available nonfirm energy on the Intertie before BPA is able to sell its nonfirm energy. Other adjustments have been made including modeling Northern California Hydro's minimum generation constraints, Intertie loopflow, and the export of non-Federal firm surplus.

In addition to these rate design and revenue forcasting efforts, BPA is taking a number of further steps to enhance the stability and reliability of its revenues. These include (1) continuing power marketing efforts in the Southwest, (2) frequent reassessment of program costs in light of changing operating needs and results, (3) improvement of financial analysis and information reporting to increase cost control, (4) development of alternative financing mechanisms for energy conservation and other resource acquisitions, (5) improvement of billing procedures, and (6) planning and development of new nonfirm energy markets in the Pacific Northwest.

QUESTION 3.c Please explain any innovative rate structures BPA has adopted in the 1983 rate adjustments, including:

(1) WPPSS adjustment clause.
(2) Computed requirements billing factors.
(3) DSI customer charge.
(4) DSI premium rate.
(5) DSI incentive rate.
(6) Hanna offpeak rate.
(7) Firm surplus power contract rate.
(8) Nonfirm surplus energy guarantee adder.
(9) Discretionary nonfirm surplus energy spill rate.
(10) Fixed nonfirm surplus energy displacement rate.
(11) End-user alternate fuel load rate.
(12) The Southern Intertie and Northern Intertie transmission rates.

RESPONSE The key rate design features of BPA's 1983 rate adjustments are described below.

1. Adjustment Clauses Two adjustment clauses have been included in the General Rate Schedule Provisions so the rates will automatically track changes in Exchange costs and Supply System costs. These clauses provide partial protection to BPA from deviations from forecasts of costs which comprise over half of BPA's revenue requirement.

The 1982 Exchange Adjustment Clause was based on the difference between the forecast average cost of the exchange and the actual average cost of designated exchange resources. In addition, the 1982 adjustment allowed only a downward adjustment; had the costs been higher than forecast, BPA would not have recovered the additional costs. The 1983 adjustment is based on the accounting net cost of all exchange resources, adjusting for deviations in both the cost and size of the exchange, and provides for either a rebate or a surcharge.

The Supply System Adjustment Clause adjusts for differences between the total cost of Supply System ownership shares of WNP- 1, 2, and 3 and the cost forecast used in the development of the rates. The adjustment, if of sufficient magnitude to be adopted, will be applied to the rates for Priority Firm Power and Firm Capacity beginning July 1, 1984.

2. Computed Requirements Billing Factors Generating publics can displace firm purchases from BPA with their own nonfirm resources and with nonfirm purchases from other utilities. Recently those customers have used that capability extensively during periods when BPA is unable to successfully market the displaced energy. BPA has redesigned the billing factors applied to these customers so that their rate is based partially on the amount of power BPA is obligated to provide on a planning basis as well as on the power actually taken.

3. DSI Customer Charge A customer charge has been added for all three possible rates, reducing the amount of revenue to be collected from variable demand and energy charges. The customer charge is applied to the greater of actual use or 90% of forecasted use. This design provides BPA with some revenue protection (about 35 percent of forecasted DSI revenues) and encourages high levels of DSI operation but allows customers considerable flexibility to vary their usage.

4. DSI Premium Rate The DSI Premium Rate is not a new rate form; rather, it is the same service described in the 1982 wholesale power rates as service to the top quartile with surplus firm energy load carrying capability (FELCC). In this rate filing BPA has designated this type of service as "Premium" service. The Premium Rate is based on the cost of firm resources allocated to provide that service.

5. DSI Incentive Rate The DSI Incentive Rate is a new rate form. This rate provides for the same quality of service as provided under the Standard Industrial Rate, but this lower rate is optional at the discretion of the Administrator and is applied on a take-or-pay basis to DSI customers who have agreed to purchaser under this rate. This rate will be implemented only when BPA's forecasts show greater overall revenues from a lower DSI rate.

6. Industrial Hanna Rate - Offpeak Rate A special offpeak rate of 7.0 mills per kilowatthour is included to allow Hanna Nickel to resume partial (primarily nighttime) operation. The offpeak rate would remain in effect until Hanna requests more than 10 percent of their Contract Demand during peak periods.

7. Surplus Firm Power Rate This rate schedule now includes four possible rates: (1) a Thermal Resource rate based on all the variable costs and up to 100 percent of fixed costs of generating and transmitting power from one or more Federal System thermal resources to point of delivery; (2) an Exchange Resource rate based on the average system cost of one or more resources; (3) a Purchased Power rate based on the cost of purchased power to BPA plus identifiable costs such as losses and transmission costs; and (4) a Contract rate based on the fully allocated cost of exchange resources and new resources. The fixed Contract rate can be used for long term sales.

Beginning July 1, 1985, an escalation factor will be applied to the Contract rate on a yearly basis to account for changes in the cost of exchange resources. The variable Exchange and Thermal rates will give BPA added flexibility to adjust to differing market conditions and make short-term sales.

8. Nonfirm Energy Rate - Guaranteed Delivery Surcharge To the extent possible, nonfirm energy will be offered with a four-day guarantee. A guaranteed delivery surcharge of 1.8 mills/kWh has been added for this service. The surcharge is based on Federal Base System thermal capacity costs. BPA may reduce amounts of nonfirm energy which are scheduled for delivery on a guaranteed basis only if it must reduce such deliveries in order to serve firm loads because of an unexpected generation loss in the Pacific Northwest or if BPA and the purchaser agree to reduce the scheduled amounts.

9. Discretionary nonfirm surplus energy spill rate The Spill rate (11.0 mills per kilowatthour) may be applied at BPA's discretion when one or more FCRPS hydroelectric plants are spilling or are forecasted to spill due to an excess of energy on the FCRPS above available markets. That is, movement from the Standard rate (18.5 mills/kWh) to the Spill rate (11.0 mills/kWh) is no longer required as a spill condition approaches. BPA will implement the Spill rate only when needed to enhance revenue.

10. Fixed nonfirm surplus energy displacement rate The Nonfirm Energy Rate has been redesigned to enhance revenue recovery and maximize thermal displacement. A Displacement rate has been added so that low variable cost resources can be displaced when BPA has more nonfirm energy than it can market at the Standard or Spill rate, whichever is in effect. A fixed Displacement rate, 7.0 mills per kilowatthour for coal and 3.0 mills per kilowatthour for nuclear, was chosen to promote ease of administration. A purchaser will qualify for the Displacement rate only if it actually shuts down or backs off generation from a resource which is not economically displaceable at Standard or Spill rate, whichever is concurrently in effect.

11. End-User Alternate Fuel Load Rate BPA will offer nonfirm energy for the displacement of loads being served with alternate fuel such as oil or gas. When Displacement rate energy is made available to end-user alternate loads, the rate will be the coal plant Displacement rate (7.0 mills per kilowatthour).

12. The Southern Intertie and Northern Intertie Transmission Rates The Southern Intertie and Northern Intertie rates provide a nonfirm transmission service. The rates are developed by the same method used on the Southern Intertie for the 1981 rate proposal. This method attempts to approximate the average cost for firm wheeling on the appropriate intertie segment.

A. Energy-Only Billing Determinant on Southern Intertie For BPA's Southern Intertie, past rate proposals have included an energy-only billing determinant, but this was only for nonfirm transmission service. The innovation in the IS-83 rate is that this charge is now expanded to any Intertie transmission service. BPA has announced its intent to develop an intertie access policy, which will further address future intertie availability charges.

B. Northern Intertie Segmentation Transmission costs for facilities between the BPA system and the U.S.-Canadian border are segmented to a Northern Intertie for this rate proposal. The costs of these facilities were previously treated in the network segment and were paid for by all network users. The facilities in the Northern Intertie are the only interconnections between the Pacific Northwest region and Canada. The definition of these facilties as a new transmission segment reflects their increased commercial use for bilateral transfers from Canada to other Northwest utilities and California.

13. Seasonal Differentiation

Because of the incorporation of the May fish flows into BPA's cost studies, May is now included as a summer capacity month and the summer-winter differential in the energy charge has widened.

4. BPA RATE PROCEDURE

QUESTION 4.a How does BPA separate the functions of advocate (staff) and decision-maker in the rate determination process?

RESPONSE BPA's rate adjustment is a rulemaking, not an adjudicative function. Therefore, the separation of functions provisions of the Administrative Procedure Act do not apply and would not be appropriate. At the conclusion of the hearing process, the Administrator makes policy decisions and structures rates for various customer classes. Facts are not being adjudicated; thus trial-type procedures such as separation of functions are inappropriate. Staff is not an advocate in the rate adjustment proceeding. Instead, BPA staff members represent the Administrator, testify concerning the initial proposal, and are subjected to cross-examination. All decisions are made by the Administrator, with the advice of expert staff.

QUESTION 4.b What is BPA's position on H.R. 3177?

RESPONSE The procedural changes proposed in H.R. 3177 would lead to a more formal, expensive, time-consuming, and litigious administrative process and one that encourages additional court challenges to BPA's rates. The current BPA rate development process is fair and open. Over 3100 citizens participated in the 1983 proceeding by expressing their views at field hearings and by submitting comments. If a more formal process is introduced in the development of BPA's rates, these individuals may find it more difficult to participate meaningfully in BPA's proceedings without the aid of attorneys and technicians.

The names of 43 parties in addition to the Northwest Power Planning Council appear on the service list. The hearing process lasted approximately 4 months. Through the hearing process, the revenue needs of the agency are redefined and the allocation of costs among customer groups and the design of rates is refined.

There is no need for a Hearing Officer to make initial rate decisions. It is inappropriate to treat issues in BPA rate adjustment proceedings as if facts were being adjudicated, thus requiring an "Independent Hearing Officer" to make quasi-judicial decisions. The Administrator is accountable to the Congress, and the Executive Branch for BPA's operations. It would be contrary to this accountability to interject an intermediate decision-maker who is not accountable either to the Administrator, Congress, or the Executive Branch.

BPA also has a very practical concern. The procedures in H.R. 3177 would make it impossible for BPA to adjust rates annually. BPA's existing power sales contracts and most of BPA's transmission contracts require that BPA give 9 months notice of rate adjustments. In the past two rate proceedings, it has taken approximately nine months from the time BPA published its initial rate proposal until it had revised rates approved on an interim basis. The procedures in H.R. 3177 would very likely add 9 months to 1 year to this already lengthy process. Such a process would impair BPA's ability to repay the Treasury.

5. FERC REVIEW OF BPA RATES

QUESTION 5.a Has FERC provided any meaningful review of BPA rates under Regional Act Subsection 7?

RESPONSE FERC has provided meaningful review of BPA's 1981 and 1982 rates. FERC has properly focused its review on ensuring that BPA's rates are set at a level sufficient to assure repayment of the Treasury. In its order confirming BPA's 1981 and 1982 rates, FERC provided constructive criticism of BPA's rates which assisted BPA in establishing its 1983 rates. The FERC order was particularly critical of what it said were overly optimistic load forecasts that resulted in excessive estimates of sales. In response to that criticism, in the 1983 proceeding BPA refined its load forecasting techniques and made more conservative assumptions concerning the marketability of surplus power.

QUESTION 5.b Would BPA favor a proposal requiring BPA to submit rate adjustments to FERC for confirmation and approval 6 months prior to the proposed effective date, if FERC were (1) required to complete its review, based on the record in BPA's proceeding, within the 6-month period, and (2) empowered to order all BPA rates increased by a uniform percentage to cover any perceived prospective revenue shortfalls?

RESPONSE If BPA were required to submit rate adjustments to FERC 6 months prior to the proposed effective date, BPA would either have to reduce the time significantly for public participation in the development of rates or forego annual rate adjustments. Such a requirement would undermine the public participation process. In addition, if current rates were significantly under-recovering revenues, a 6-month filing requirement would jeopardize BPA's ability to meet its revenue requirement and repay the Treasury.

6. COST-EFFECTIVENESS OF WPPSS 3

QUESTION 6.a What are the conclusions of BPA's most recent analyses of the cost-effectiveness of resuming construction of WPPSS 3? Please provide the important assumptions and methodology used to derive these conclusions.

RESPONSE BPA's analysis is not yet complete. We expect to complete it during the week of October 24, 1983. Those portions of the analysis which are finished indicate that:

(1) Completion of WNP-3 continues to be cost-effective. Under base case load forecast assumptions, the region would face an increase in total power supply costs in excess of $1 billion if WNP-3 is terminated and replaced with alternative resources.

(2) While various construction restart dates are being studied, there appear to be no compelling resource economic reasons favoring early restart over later restart, provided restart occurs within 3 to 4 years.

(3) The current unavailability of financing for project construction and unresolved legal issues surrounding the Supply System leave the region without assurances that construction could continue unimpeded once restarted and could expose BPA and the region's ratepayers to risks of construction disruptions.

(4) A 3 to 4 year delay in commercial operation can be accommodated without creating regional deficits under BPA's new base load forecast. Sufficient regional resources will be available to meet the region's firm loads.

The new analysis is based on forecasts of long-term system costs and export revenues under a variety of restart and completion schedules for WNP-3 as well as under several termination scenarios. Capital costs to complete have been provided by the Supply System for seven alternative restart cases. The System Analysis Model and Least-Cost Mix Model are used to forecast total system costs.

Sensitivity analyses are being conducted on key variables including load growth rates between 1.3 percent and 2.6 percent, export sale prices ranging from 9 mills to 45 mills per kWh, conservation ranging from 1000 MW to 2500 MW, interest rates up to 15 percent on new Supply System bond sales, and costs for new generic thermal resources ranging from 30 mills to 65 mills per kWh.

BPA will publish the results together with a description of methodology and assumptions. A copy will be furnished to the Subcommittee.

QUESTION 6.b How soon could construction resume at WPPSS 3? If any key managers of the project have been lost, how long would it take to replace them? How much of the workforce (managerial and manual) has been laid off or terminated? How many of these persons have left the Satsop area for work elsewhere?

RESPONSE The present plan for an extended construction delay includes the capability for restart of construction. Construction activity could resume about 30 to 60 days after direction to restart is given. It would, however, be approximately 9 to 12 months before construction activity would reach its peak. Contractor nonmanual employees such as site engineers, quality assurance personnel, and contract administrators must be hired before many of the contractor craft employees in order to insure an orderly resumption of construction.

While there have been changes in certain key management personnel, all such positions are filled with the exception of the Startup Managers. Due to the construction rampdown, those positions will not be filled until construction resumes. However, modified activities to support startup are included in the extended construction delay plan.

At the end of February 1983 when construction activity was proceeding at a normal pace, the project personnel total was 3,844. By the end of September 1983, the total was 1,158. The elements of these totals are shown below by job category:

	February 1983 Actual	September 1983 Actual
Contractor - Craft	1,768	149
Contractor - Nonmanual	733	285
EBASCO - Construction Mgt.	457	261
EBASCO - Architect/Engineer	427	198
Supply System	459	265
Total	3,844	1,158

While no detailed studies have been conducted, BPA and the Supply System estimate that 75 percent of the nonmanual personnel and 70 percent of the craft people directly assigned to the project site who have been laid off are no longer in the Satsop area. Since most of the craft people were "travelers," it is expected that they will return when construction resumes. The majority of the nonmanual employees are permanent company employees and the contractors would be expected to staff the project adequately when construction restarts.

QUESTION 6.c Under BPA's latest load projections, is it economical to—

(1) Restart construction on WPPSS 3 as soon as possible?
(2) Resume construction of WPPSS 3 after a period of preservation?
(3) Terminate WPPSS 3?

RESPONSE As mentioned in 6.a above, BPA's analysis which will enable us to answer this question is not yet complete. The response to 6.a above also applies to this question.

7. BPA CONSERVATION PROGRAMS AND CONTRACTS

QUESTION 7.a How much of the $1.5 billion in borrowing authority for conservation and renewable resource development under P.L. 96-501 (Regional Act) has BPA used?

RESPONSE The Regional Act provided $1.25 billion in borrowing authority for conservation and renewable resources. A $140 million bond was issued on September 30, 1983, against the borrowing authority provided by P.L. 96-501. Based on preliminary reports, during fiscal years 1982 and 1983, BPA incurred approximately $150 million in additional conservation obligations against which it intends to issue bonds.

QUESTION 7.b What restrictions have OMB or the Treasury Department imposed on BPA's use of this borrowing authority?

RESPONSE Last year's budget submission for Congressional review indicated a total of $121 million in Treasury borrowing to support the conservation budget. Due to external financing problems associated with the insolvency of the Washington Public Power Supply System, BPA later requested an FY 1984 apportionment containing a total of $183.8 million in Treasury borrowing for conservation. That request was denied by OMB. BPA has requested that the Department of Energy appeal this decision to the OMB. BPA's request is currently being reviewed by the Department.

QUESTION 7.c How much of the $58.4 million of "external financing" for conservation, shown in BPA's latest revised FY 1984 budget submitted to Congress on June 22, 1983, has actually been arranged?

RESPONSE To this date, no external financings of the conservation acquisition programs have been completed. However, BPA is about to consummate transactions for a $15 million financing of the next 3 years operation of the weatherization program in Eugene, Oregon. In addition BPA is currently operating 5 external financing field tests which will result in a conservation investment of $250,000.

QUESTION 7.d Does BPA require additional Congressional approval in order to use its borrowing authority under P.L. 96-501 to cover deficiencies in external financing for conservation?

RESPONSE There are currently no Congressional restrictions to our exercising any part of the borrowing authorized by P.L. 96-501. BPA, however, must notify the Appropriations Committees of any increase in projected use of its borrowing authority in FY 1984 above currently budgeted amounts. Once the appeal noted in Response to 7.b is resolved, the Congress will be notified as to the FY 1984 Treasury borrowing level for BPA's Energy Conservation Program.

QUESTION 7.e Which utilities have signed BPA's long-term conservation contracts? Which have not? Please compare signers and nonsigners in terms of (1) total load, and (2) load on BPA.

RESPONSE As of October 20, 1983, 61 utilities and two states (Oregon and Washington) have signed at least one of the offered contracts. The remaining 68 have until October 31, 1983, to sign and return contracts to BPA. The loads for each of these groups, as presented in the 1983 Cost of Service Analysis, are as follows for operating year 1984:

	Signers	Nonsigners
Total load	2,731.1 average Mw	15,002.0 average Mw
BPA load	2,546.9 average Mw	5,787.8 average Mw

The list of the entities that have signed long-term conservation contracts with BPA as of October 14, 1983 follows:.

Albion, City of
Ashland, City of
Bandon, City of
Benton County PUD
Benton REA
Big Bend Electric Cooperative
Blaine, City of
Blachly-Lane County Cooperative
Cheney
Clallam County PUD
Clark County PUD
Columbia Basin Electric Co-op
Columbia Power Cooperative
Columbia REA
Consumers Power
Coos-Curry Cooperative
Douglas Electric Cooperative
Drain, City of
Ellensburg, City of
Elmhurst Mutual Power & Light
Farmers Electric
Ferry County PUD
Fircrest, Town of
Forest Grove, City of
Idaho County Light & Power Co-op
Inland Power & Light
Kittilas
Klickitat County PUD
Kootenai
Lakeview Light & Power
Lane Electric Cooperative
Lincoln Electric Cooperative (Mont.)
Lincoln Electric Cooperative (Wash.)
Lower Valley Power & Light
Mason County PUD No. 1
Mason County PUD No. 3
McCleary Light & Power
McMinnville, City of
Milton-Freewater
Monmouth, City of
Ohop Mutual Light
Orcas Power & Light
Oregon, State of, Low Income Residents
Parkland Light & Water
Peninsula Light
Port Angeles, City of
Richland, City of
Riverside Electric
Rural Electric
Salem Electric
Snohomish County PUD
South Side Electric
Springfield Utility Board
Steilacoom, Town of
Surprise Valley
Tanner Electric
Umatilla Electric Cooperative
Vera Irrigation District
Wahkiakum County PUD
Wasco Electric Cooperative
Washington, State of, PCAA
Wells Rural Electric
West Oregon Electric Cooperative

QUESTION 7.f What are the objections of those utilities which have indicated they will not sign the contracts? How does BPA plan to resolve these objections?

RESPONSE The key objections, as obtained by BPA's Area offices, relate to:
A. The contract charge.
B. Conservation in a period of surplus.
C. Certain provisions of the General Conservation Contract.

A. The contract charge. BPA made a major change in the structure of the contract charge from its appearance in the initial BPA rate proposal in March 1983 to its appearance in the final proposal in September 1983 to respond to testimony in the record of the rate hearings. The rationale for the change, as well as for the charge itself, is contained in the Administrator's Record of Decision.

B. Conservation in a period of surplus. BPA has restructed and paced the conservation acquisition programs to achieve the least costly response to the long-term regional need for new power resources. BPA has also committed to developing the capability to pursue future energy savings available in the commercial, industrial and agricultural sectors, pursuant to the Northwest Power Planning Council's Two-year Action Plan.

C. Certain provisions of the General Conservation Contract Provisions (GCCP). One subject of some customer concerns has been Section I(A)(4)(B), pertaining to BPA's ability to effect changes unilaterally in a certain class of program features--those which assure the cost-effectiveness of the program. Their concerns no longer seems to be a major obstacle. BPA has clarified, at the customers request, two other GCCP provisions: (1) indemnification and (2) method of calculating a customer's maximum liability under the Alternative Charge provision - section 32(d).

QUESTION 7.g What were the conclusions of BPA's environmental impact statement (EIS) on indoor air quality aspects of residential weatherization? How does BPA plan to modify or limit its weatherization programs to reflect these conclusions? How much conservation saving would be lost as a result? How has BPA quantified and considered the economic and environmental impacts of such lost savings? Would a residential weatherization program with selective installation of heat exchangers result in positive net economic and public health benefit?

RESPONSE BPA's Draft EIS on expansion of its Residential Weatherization Program does not identify a preferred alternative. This will be done in the Final EIS, after the information and comments received during the public review period have been analyzed. After completion of the Final EIS, BPA will decide whether and how to modify the current restricted Weatherization Program. In making this decision, BPA will balance the energy savings, and economic and environmental impacts associated with various courses of action, which are described and quantified in the EIS (see Table 7.g-1 pages 1 and 2 outlining and EIS summary).

In general, the Draft EIS indicates the following:

1. Under baseline conditions (no BPA Residential Weatherization Program), normal concentrations of indoor air pollutants are estimated to account for between 31 and 744 lung cancers annually among the region's

3.2 million people who live in electrically heated homes. The wide range in this estimate reflects uncertainty about pollutant concentration levels, exposure time, and the relationship between dosage and health effects. National statistics indicate that over an entire lifetime, an individual has a 4-percent chance, or 128,000 in 3.2 million, of contracting lung cancer from all causes. The national average lifetime risk of lung cancer from indoor air pollutants is 7 percent of that 4 percent, or 28 chances out of 1 million.

2. If BPA's current restricted Weatherization Program were applied to all eligible homes in the Pacific Northwest, between 0.2 and 10.5 lung cancers would be added annually to the baseline. This would increase the risk of lung cancer from all causes from 4 percent to 4.0036 percent.

3. The analysis in the Draft EIS also indicates that BPA's current Weatherization Program is expected to achieve 191 annual average megawatts of energy savings. An additional 74.4 annual average megawatts have been identified as the energy savings potential which could be realized from the application of tightening measures in homes from which they are currently excluded.

4. The Draft EIS contains quantitative information on the environmental effects of generating resources which would be needed if energy savings cannot be realized either from the current restricted Weatherization Program or the proposed complete program. See the EIS summary and pages 4.46-4.49 in the main report for information on these effects, and a description of the methods used to quantify them.

5. The health effects, direct dollar costs and energy savings losses of the mitigation strategies are also assessed in the Draft EIS. The strategies range widely from excluding certain types of homes from the Program (e.g., homes with wood stoves) to selective installation of air-to-air heat exchangers (e.g, only in those homes which have certain characteristics and where radon levels are shown to exceed 3 picocuries per liter). Although it is possible that selective installation of air-to-air heat exchangers may have positive net economic and public health benefits, this will depend upon several factors including the level of pollutants actually found in residences, the final installed costs of air-to-air heat exchangers (now estimated at about $650 each), the energy consumed by the heat exchangers, and the avoided costs of generating resources which would not have to be built if conservation programs are implemented. Critics of the Draft EIS have already pointed out that the economic effects of the alternatives and mitigation strategies need to be examined in greater detail, and this will be done in the Final EIS.

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TABLE 7.g-1 (page 1 of 2)

Summary of Environmental Impacts

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Table 7.g-1 (page 2 of 2)

Summary of Environmental Impacts

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8. NORTHWEST SURPLUS POWER SALES TO CALIFORNIA

QUESTION 8.a What progress have BPA and the other Northwest utilities made in marketing surplus firm power to California since the Subcommittee's hearing in Eugene on July 11, 1983?

RESPONSE To date, BPA has made a number of short-term sales at 28.4 mills per kilowatthour to California entities following its notice on August 23, 1983, that 1350 average MW of surplus firm energy would be available for the months of September and October:

week of	amount	customer
Sept 25-Oct 1	average 400 MW	PG&E
Sept 1-30	average 250 MW	Central Valley
Oct 3-9	average 400 MW	PG&E
Oct 10-16	average 500 MW	PG&E
	average 200 MW	SCE
October 17-23	average 400 MW	PG&E
	average 200 MW	SCE
Oct 1-31	average 120 MW	Central Valley

Further, in a notice dated September 30, 1983, BPA revised its figure of the amount of available surplus power to approximately 1000 average megawatts of surplus firm power on the BPA system from November 1, 1983, through January 31, 1984. Consequently, BPA has offered power sale contracts to all its customers under which such surplus firm sales could be concluded. Sales will begin November 1, 1983. BPA hopes to make a block sale for the full 3-month period but will consider shorter-term sales on an as-available basis. The price will depend upon the spot market. Under the proposed Schedules SP-83 and SR-83, BPA can set a rate for the sale of surplus power and surplus energy which reflects the costs to BPA of obtaining power from exchange or thermal resources or the purchase price of power to serve such contracts, or a negotiated contract price which covers BPA's cost. BPA may mix the costs for these various bases in arriving at a rate for the sale of surplus power.

On a continuing basis, BPA will monitor the available amounts of surplus firm power on the system and from time to time inform its customers of the amount available and its price. A copy of the draft contract under which such sales will most likely occur is attached for the Committee's information.

QUESTION 8.b What amounts of surplus firm power can the Northwest offer and at what price?

RESPONSE The Pacific Northwest region is, for the baseload forecast, currently facing a firm surplus ranging from 1350 MW in 1983-84 to 1600+ MW in 1985-86 before declining to zero (balance) in 1989. Table 1 summarizes the region's load/resource situation for the base load forecast for the period 1984 through 2003. The balance assumes that Supply System Plants WNP-1, WNP-2, and WNP-3 are on-line in June 1991, February 1984, and December 1989, respectively. Hydro energy estimates are the average of the critical period (that portion of the historical 40-year streamflow which, when combined with draft of all available reservior storage, will produce the least amount of energy). Since the short-term surplus disappears by 1989, the region can only support a long-term firm export sale if additional resources are installed. Potential resource mixes have been analyzed for long-term exports and the projected additional resource costs have been considered in development of the offer which the Pacific Northwest Utilities Conference Committee (PNUCC) marketing group has placed before the California utilities.

The PNUCC marketing group has suggested two possible long-term contract alternatives. The first would provide 1500 megawatts of energy at 40-45 mills/kWh increasing to 60-65 mills/kWh in real 1983 dollars in 5 years, then estimated to increase to a cost of about 75-80 mills/kWh by the end of the 15-year period, with a 5-year recall. The second sets the price for 10 years at approximately 60 mills/kWh, 50 mills/kWh fixed, and 10 mills/kWh variable (in real 1983 dollars) where the 50 mills remains constant over time but the variable component increases as coal fuel costs increase. The price during the last five years would very depending on the resources used to serve the load. There has, as of yet, been no response from the California utilities. The role that BPA might play in the marketing of surplus firm power from other Northwest utilities has yet to be defined and agreed upon.

QUESTION 8.c What arrangements has BPA made to assist the British Columbia Hydro & Power Authority dispose of its own expected surplus of firm power?

RESPONSE BPA has begun preliminary discussions with B.C. Hydro on firm surplus power resources that B.C. Hydro has available to market outside the Province. Because these discussions have only begun and B.C. Hydro is in the process of formulating a marketing program internally, neither principles nor specific proposals have been explored. The initial discussions have been confined to the exchange of information on firm surplus availability and the explanation of very broad concepts.

QUESTION 8.d What policies is BPA considering for determining which utilities shall have access to the Pacific Intertie for making power sales to California?

RESPONSE BPA has given notice of its intent to develop an access policy for the Pacific Northwest/Pacific Southwest Intertie, with a request for recommendations in a Federal Register Notice of July 1983. BPA is considering the recommendations received in response to that notice in the development of a proposal for the Intertie Access Policy, tentatively planned for publication in early 1984.

Some of the major concepts being considered in that policy development are as follows:

1. The identification of an amount of Intertie transmission capability which will be required for Federal power;

2. The application of the priority granted pursuant to section 9(i)(3) of the Regional Act which states:

> The Administrator shall, to the extent practicable, give priority in making such services available for the marketing, within and without the Pacific Northwest, of capability from projects under construction on the effective date of this Act, if such capability has been offered for sale at cost, including a reasonable rate of return, to the Administrator pursuant to this Act and such offer is not accepted within one year;

3. The relationship between the Intertie Access Policy and the Exportable Energy Agreement which presently allocates transmission access under certain conditions;

4. The consistency of a resource with the Regional Council's Plan;

5. The need to hold harmless the residential purchase and exchange sale/average system cost arrangements from the effects of transactions making use of Intertie Access; and

6. The potential for providing Intertie Access Services in such a way as to support beneficial firm sales between the Pacific Northwest and Pacific Southwest regions.

QUESTION 8.e What now appear to be the most promising alternatives for increasing transmission capacity between the Northwest and Southwest? What steps is BPA taking to ensure that such capacity is developed?

RESPONSE BPA is currently working with Northwest and Southwest utilities to analyze short and longer-range intertie alternatives. Alternative 1 represents an uprate with potential application in the 1984-87 timeframe. The Transmission Subcommittee of the Inter-Regional Marketing Group is studying longer-range transmission alternatives that might be available by 1991, which are listed as alternatives 2-4. The alternatives are:

1. Upgrading the existing Pacific Intertie ac lines from 2800 MW to 3200 MW (please see Exhibit 8.e-1).

   With the completion of the Buckley-Summer Lake 500-kV line in 1983 and installation of new series capacitors south of Table Mountain scheduled for June 1984, the rating of the Pacific AC Intertie can be increased from its present 2800 MW to 3200 MW. Other work supporting this upgrade includes uprating the WAPA series capacitors at Malin and looping the Buckley-Summer Lake line into the series capacitors at Bakeoven. The incremental cost to increase the AC Intertie to 3200 MW is approximately $2 million.

   Recent studies indicate that there could be some limitations to using the full capacity when Arizona to California transfers are high.

2. Building an additional 500 kV-ac line from Malin, Oregon to the Tesla substation east of San Francisco (please see Exhibit 8.e-2).

   This facility would be constructed from Malin Substation near the Oregon/California border to Tesla Substation east of San Francisco, a distance of about 355 miles. It would parallel the two existing Pacific AC Intertie lines but not necessarily use the same right of way.

   The estimated 1983 investment cost of this project is $340 million, which includes $50 million for the addition of an 85-mile, 500-kV line from the Los Banos Substation to the Gates Substation in Southern California. Since there are other options that will be explored for reinforcing the system south of Tesla, such as by uprating the series capacitors between Los Banos and Midway, the cost for the project may vary.

   Because of potential siting problems, the completion date for this project is estimated to be 1991 to 1993. The addition of a third ac line can increase the capacity of the Pacific AC Intertie by more than 1500 MW.

3. Building an additional 1000 kV-dc line from Celilo near The Dalles, Oregon, to Mead, near Las Vegas (please see Exhibit 8.e-3).

   A second HVdc line was authorized as a part of the Pacific Intertie. The line was originally planned to be constructed between Celilo Substation, Oregon, and Mead Substation near Boulder City, Nevada. Further study is needed to determine the best locations for the converter terminals. There are several possible locations for the terminal in the Northwest (Celilo, Malin, Summer Lake, or Buckley) and the Southwest (Mead, Los Angeles area, or combination).

   Assuming that the dc line would be constructed between Celilo and Los Angeles, a distance of 845 miles, the estimated 1983 investment cost would be $595 million. This includes the cost of ac system reinforcements at the terminals. Since most of the right-of-way would be available for this route, the line may be completed by 1991 and possibly earlier. The second HVdc line is expected to add about 2200 MW of intertie capacity.

4. Building an inland intertie from the Idaho/Montana area to the Southwest (please see Exhibit 8.e-4).

   A trans-Sierra line can be a part of an "Inland Intertie" which would consist of constructing a line from the Idaho/Montana area, extending through Utah, or Nevada into the Arizona/California area. It might involve either ac or dc transmission, and could be integrated with other proposed generation or transmission additions in the areas mentioned.

   There are several variations to the inland intertie concept that are being considered with varying costs. The ac alternative which is being considered consists of a 500-kV ac transmission line from the Garrison Substation in Montana, connected through the Midpoint Substation in Idaho and the Sierra Pacific Power Company system, to the Tesla Substation east of San Francisco, California, a distance of approximately 865 miles. The dc alternative considered would differ by having an HVDC line from the Midpoint to the Los Angeles area.

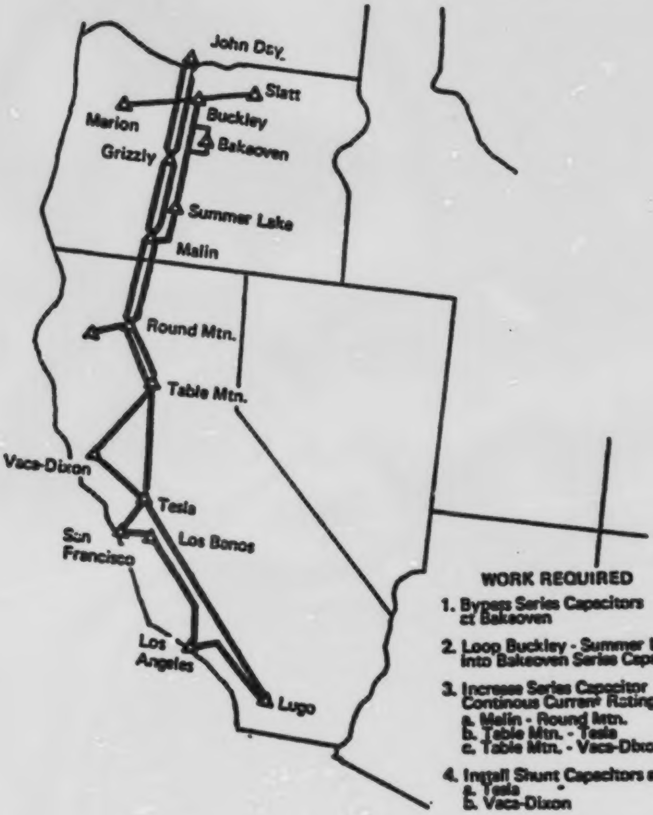
   Because of the length of the route and the many entities that will be involved, the earliest completion date is expected to be 1991. This Inland Intertie could add about 1500 MW to the Northwest-Southwest Intertie capacity.

BPA is actively supporting the Transmission Subcommittee's efforts to explore the various alternatives and is continuing our own studies and efforts relating not only to new intertie construction, but also to upgrading existing facilities' transfering capabilities.

EXHIBIT 8.e-1

Upgrade A.C. to 3,200 MW

PNW/PSW INTERTIE OPTIONS


John Day
Slatt
Marion
Buckley
Bakeoven
Grizzly
Summer Lake
Malin
Round Mtn.
Table Mtn.
Vaca-Dixon
Tesla
San Francisco
Los Banos
Los Angeles
Lugo

WORK REQUIRED

1. Bypass Series Capacitors at Bakeoven
2. Loop Buckley - Summer Lake into Bakeoven Series Capacitor
3. Increase Series Capacitor Continous Current Rating in:
   - a. Malin - Round Mtn.
   - b. Table Mtn. - Tesla
   - c. Table Mtn. - Vaca-Dixon
4. Install Shunt Capacitors at:
   - a. Tesla
   - b. Vaca-Dixon

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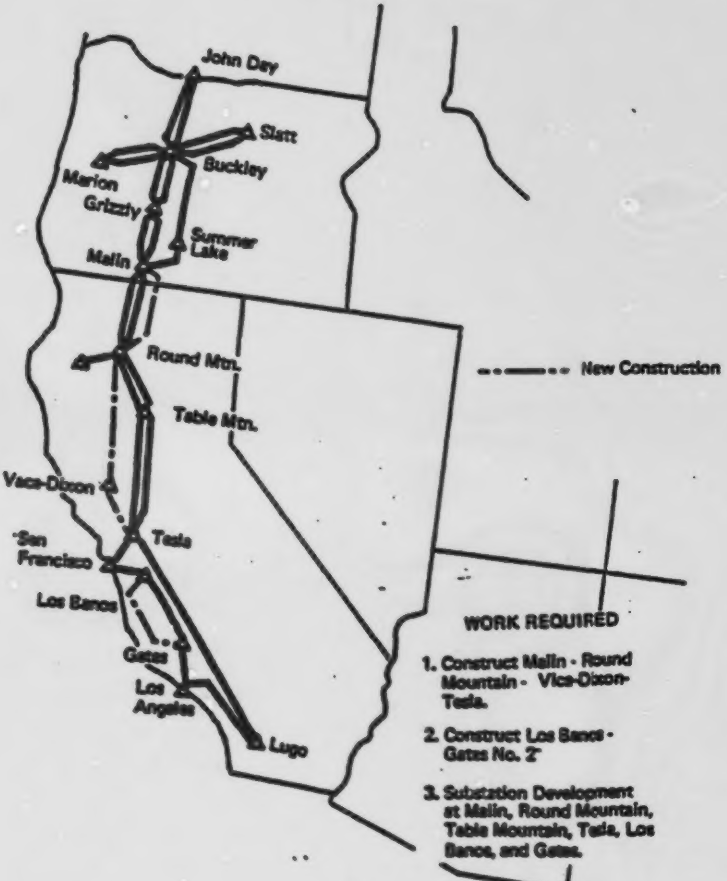
EXHIBIT 8.e-2

Third A.C. 500kV line

PNW/PSW INTERTIE OPTIONS


John Day
Slatt
Buckley
Marion
Grizzly
Summer Lake
Malin
Round Mtn.
Table Mtn.
Vaca-Dixon
Tesla
San Francisco
Los Banos
Gates
Los Angeles
Lugo
New Construction

WORK REQUIRED

1. Construct Malin - Round Mountain - Vica-Dixon-Tesla.
2. Construct Los Banos - Gates No. 2
3. Substation Development at Malin, Round Mountain, Table Mountain, Tesla, Los Banos, and Gates.

EXHIBIT 8.e-3

2nd D.C. line

PNW/PSW INTERTIE OPTIONS

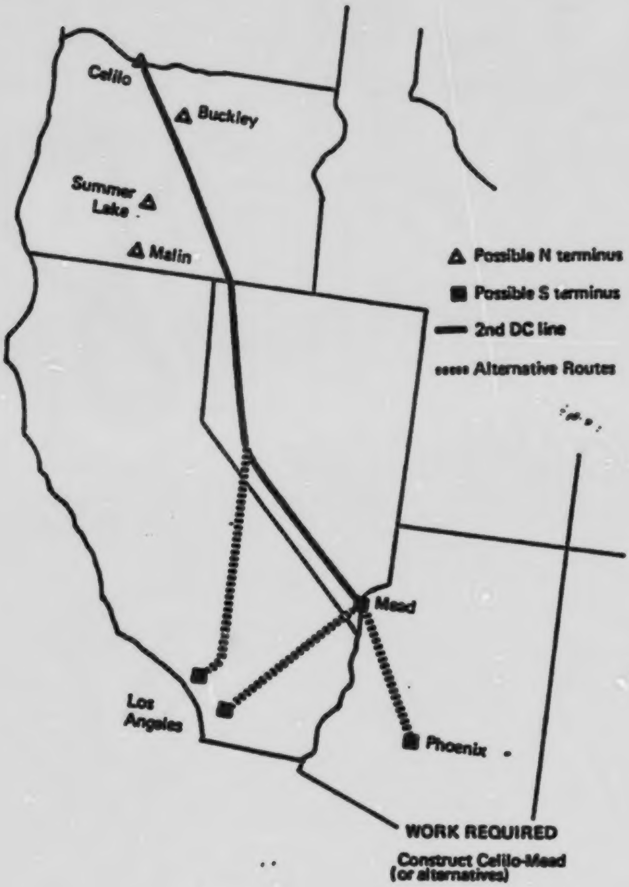
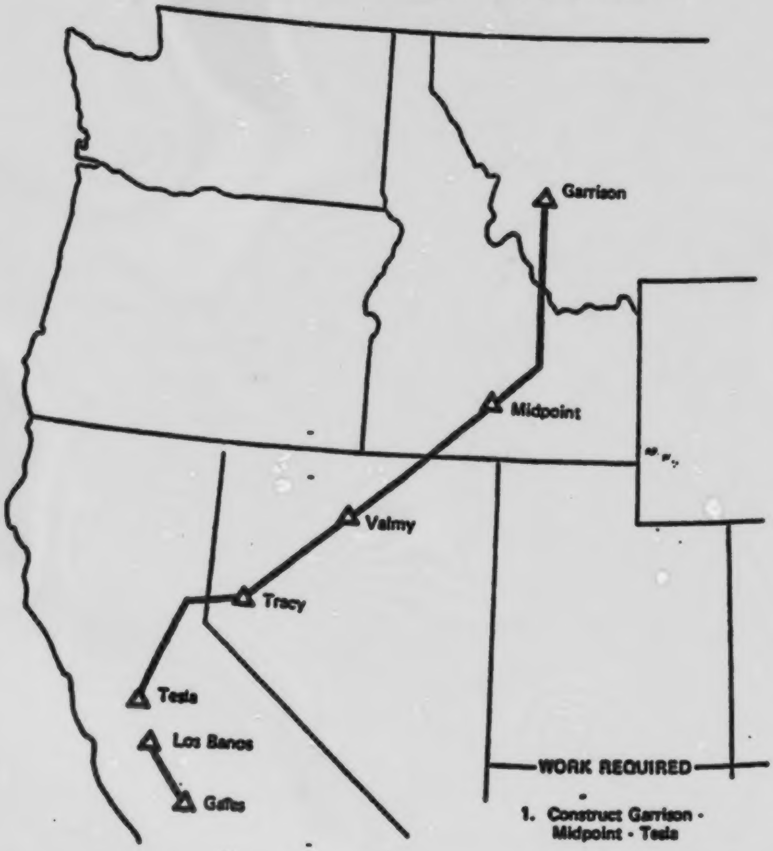

Celilo
Buckley
Summer Lake
Malin
Mead
Los Angeles
Phoenix
▲ Possible N terminus
■ Possible S terminus
━ 2nd DC line
••••• Alternative Routes
WORK REQUIRED
Construct Celilo-Mead (or alternatives)

EXHIBIT 8.e-4

Inland Intertie (Garrison–Midpoint–Tesla 500kV AC line)

PNW/PSW INTERTIE OPTIONS


Garrison
Midpoint
Valmy
Tracy
Tesla
Los Banos
Gates

WORK REQUIRED

1. Construct Garrison - Midpoint - Tesla
2. Construct Los Banos - Gates No. 2
3. Substation Development at Garrison, Midpoint, Valmy, Tracy, Tesla, Los Banos, and Gates

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

OFFICE OF THE ADMINISTRATOR

In reply refer to:

October 26, 1983

Honorable John D. Dingell
Chairman
Committee on Energy and Commerce
House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

This responds to your request for the views of the Department of Energy (DOE) on H.R. 3177, 98th Congress, the "Bonneville Power Administration Fair Ratemaking Act of 1983."

The purpose of this bill, as expressed by its sponsor, is to establish a "more fair and open" Bonneville Power Administration (BPA) ratemaking process and "avoid costly and time consuming administrative and judicial appeal." 129 Cong. Rec. E2586 (daily ed. May 26, 1983) (Statement of Rep. Wyden). DOE is concerned, however, that the procedural changes it proposes would lead to a more formal, expensive, time consuming, and litigious administrative process and one that would encourage additional court challenges to BPA's rates. Accordingly, DOE opposes the enactment of H.R. 3177.

The bill would make fundamental changes to the procedures now required for BPA to adjust rates. First, the bill would establish a Hearing Officer as an independent decisionmaker who would be required to render an initial decision. Second, rates based on the Hearing Officer's decision would become final in sixty days, unless the Administrator changed those rates and provided a full and complete justification for differences between the Administrator's final rates and rates based on the Hearing Officer's decision.

The current BPA rate development process is a fair and open ratemaking process. The participant list in BPA's 1983 proceeding numbers 3,110 citizens. The concerns expressed by these individuals appear in BPA's Evaluation of the Record and the Record of Decision. By introducing a rigid and more formal process to the development of BPA's rates, these individuals may find it more difficult to participate meaningfully in BPA's proceedings without the aid of attorneys and technicians.

The purpose of the hearing now held under section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (the "Regional Act") (16 U.S.C. § 839e(i)) is to give parties a forum in which to make suggestions for changes, which the Administrator may adopt at the conclusion of the socalled 7(i) hearing. Frequently the Administrator's final rates will differ from the initial rate proposed because the nature of the hearing process is to refine and redefine the revenue needs of the agency. The process additionally refines the methods used for allocating costs among customer groups and for designing rates. The purpose of the hearing is to give parties an opportunity to submit their positions on these issues, with a view toward the Administrator refining his initial proposal. In the 1983 case, the names of 43 parties in addition to the Northwest Power Planning Council appear on the service list. The hearing process lasted approximately four months, including clarifying sessions, crossexamination, rebuttal, and oral argument.

The additional hearing provision in the bill would require an additional round of rebuttal and crossexamination. If, based on the second round of hearings, BPA adopted any of the parties' arguments by revising rates again, yet another round of rebuttal and crossexamination would be required. This provision would make more cumbersome each rate adjustment proceeding without commensurate improvement of the quality of the decision reached. This in turn would jeopardize the Administrator's ability to put rates into effect in an expeditious manner to assure repayment of the Treasury and meeting total system costs. For example, during the 1983 rate proceeding, it was determined that a one month delay in the effective date for new rates would result in revenue loss to BPA of $30 million, thereby jeopardizing BPA's ability to make payments to the Treasury.

The proposal that the Hearing Officer make the initial rate decisions begins from an underlying misconception of the ratemaking process for power marketing administrations (PMAs). Ratemaking is rulemaking, a legislativetype process. Facts are not being adjudicated as in a trial type proceeding. There is no need for an "independent Hearing Officer" to decide, for example, based on various arguments made, whether Saturday should be treated as a peak or an off-peak day. The Administrator makes his policy decision based on the hearing record. Rates are established for a prospective period of time, and policy choices are made concerning revenue level, load forecasts, and various cost allocations and rate designs.

It is, moreover, inappropriate to treat these issues as if facts are to be adjudicated and require an "independent Hearing

Officer" to make initial quasijudicial decisions. Congress directed in section 7(a)(1) of the Regional Act that "[t]he Administrator shall establish, and periodically review and revise, rates ...." To interject an intermediate decisionmaker who is not accountable to the Administrator, any other executive official, or the Congress would be contrary to well established principles of accountability.

It is also inappropriate to assume that the Hearing Officer for BPA's current rate proceeding is a passive observer. On the contrary, the Hearing Officer for the 1983 proceedings actively took part in questioning witnesses, requesting proposals, and testing the theories and assumptions of all parties and witnesses. The Hearing Officer assured the development of a thorough and complete record for consideration by the Administrator.

Although public participation in ratemaking had been prescribed administratively, until relatively recently the several power marketing administrations, including BPA, were not required by statute to afford their customers any kind of formal process. See, United States v. Tex La Electric Cooperative, 693 F.2d 392 (5th Cir. 1982). Through section 7(i) of the Regional Act, Congress created a formal process that BPA observes in establishing rates. Parties have the right to crossexamine witnesses, including all BPA witnesses, and refute and rebut all materials submitted to or developed by the Administrator. The administrative records from the 1981 and 1982 proceedings exceed 15,000 pages each. Despite the formal process and procedural protections afforded by section 7(i) of the Regional Act, litigation concerning BPA's rates has increased, not decreased. Prior to 1979, no BPA customer had ever filed suit against BPA. Since passage of the Regional Act, over 40 lawsuits have been filed by BPA's customers and other interests, with approximately 20 suits currently pending concerning BPA's rates alone. While the Department shares Congress' desire to eliminate endless litigation, additional "formal process" will be counter productive to that goal.

DOE also shares the concerns of many in Congress that BPA rates be set at a sufficient level to recover the Administrator's total system costs and repay the Treasury. In the past three rate cases, including the current case, BPA has been striving to meet that goal and still afford the parties the procedural protections mandated by section 7(i). Under present law, it takes approximately nine months from the time BPA publishes proposed rates in the Federal Register until BPA has revised rates in place on an interim basis. This includes review by the Federal Energy Regulatory Commission prior to placing rates into effect on an interim basis. These are only interim rates, subject to refund. Before rates are final, FERC must review them. The bill's requirements of an initial decision by a hearing officer, coupled with the ability of the Administrator to alter that initial decision within sixty days, will add at least five months, and very likely nine months to one year, to this already lengthy process. An additional one to four months of hearings could be required if the Administrator sought to revise rates from the initial proposal at the completion of the first round of hearings, thereby making the total additional time well over one year.

The BPA rate adjustment process under the bill is likely to take between 18 months and two years. In the face of rising costs and uncertainties concerning the region's power supply situation, extending the period within which the Administrator may adjust rates beyond 12 months would seriously affect the Administrator's ability to make payments to the Treasury.

Enactment of H.R. 3177 would not have a substantial impact upon the budgetary requirements of the Department of Energy.

The Office of Management and Budget advises that from the standpoint of the President's program, there is no objection to the presentation of this report for the consideration of the Congress.

Sincerely,

Peter T. Johnson

Peter T. Johnson
Administrator

STAFF REPORT

WNP-3 Resource Economics and Construction Schedule Update

BONNEVILLE POWER ADMINISTRATION

OCTOBER 26, 1983

INTRODUCTION

This report contains the results of an update of WNP-3 resource economics and an evaluation of various WNP-3 construction schedule alternatives. Similar to previous Bonneville Power Administration (BPA) studies, alternatives in this report are evaluated and presented from three perspectives:

I. Long-term resource economics,
II. Financial implications, and
III. Rate and load impacts.

BPA has undertaken this effort to incorporate the best current resource information now available, including BPA's new long-term load forecast released in August 1983. The proposed committee report language accompanying the legislation which was recently introduced in Congress would have mandated that BPA perform careful economic, load/resource, and rate impact analysis before concluding upon any additional financing and restart of WNP-3 construction. This analysis was prepared to allow BPA to respond expeditiously to congressional questions concerning these issues. In addition, it will be helpful when and if other prudent financing is identified. This analysis includes various construction scenarios, provided by the Washington Public Power Supply System (Supply System), ranging from a possibility that construction would be restarted in early 1984, if financing were in place and other issues resolved, to a potential restart in late 1985, which is the earliest date additional funding might be available directly through BPA rates. This analysis considers ranges of financing costs, the impact of various surplus marketing considerations, and a variety of construction scenarios defined by the Supply System. This work has been coordinated with the Supply System, other owners of WNP-3, all BPA customer groups, the Northwest Power Planning Council (Council), the Pacific Northwest Utilities Conference Committee (PNUCC), and other interested parties.

After a brief section on the context of the evaluation and the alternatives considered, this staff report presents the findings of the economics, rates, and financial evaluations.

Beginning on June 1, 1983, the Supply System commenced a ramp-down and preservation of Supply System Nuclear Plant No. 3 (WNP-3) consistent with a 3-year extension in the project's schedule. This action was necessitated by an inability to conventionally finance continued construction of the project and the adverse financial impact on BPA and its regional customer utilities that would have resulted from an attempt to fund continued construction directly from BPA revenues. The current and projected regional load/resource situation permitted a 3-year construction extension without jeopardizing the region's ability to meet anticipated firm loads. Currently, the onsite ramp-down of construction is in progress, and WNP-3 should be in a full preservation state by mid-1984.

Since June 1983, there have been a number of additional developments.

1. Intensification of Litigation. The court cases surrounding the Supply System Nuclear Plants No. 4 and 5 (WNP-4/5) default continue to grow in number and in complexity. Major cases not finally judicially resolved include WNP-4/5 securities fraud allegations, attempts to attach net-billed project (WNP-1/2/3) assets by WNP-4/5 creditors, litigation associated with cost sharing between WNP-4/5 costs and net-billed project costs, challenges to the net-billing agreements, and a dispute with the investor-owned utility owners of WNP-3 regarding its ramp down and preservation. The focus, therefore, of regional issues regarding WNP-4/5, and to a lesser extent the net-billed projects, has now moved primarily into the courts.

2. Governors' WPPSS Advisory Panel. On July 7, 1983, the Governors of Washington and Oregon appointed a special panel to investigate issues surrounding the Supply System and to recommend solutions. Charles Luce, Edward Carlson, and Herbert Schwab were appointed to this panel, and its report is currently scheduled to be released in mid-November 1983.

3. Legislative Activities. Legislation has been considered by the Congress that would enable BPA to use its existing authority to finance continued WNP-3 construction. This legislation has been considered by the Senate Energy and Natural Resources and Appropriations Committees as well as the

Commerce and Energy Committee of the House of Representatives. Several members of the regional congressional delegation have stated that legislative action appears desirable and should be considered after the Governors' WPPSS Advisory Panel's report is released and other information is available. BPA views the proposed legislation as a desirable first step.

4. Preservation Enhancement Program. The Supply System has initiated a program focused on WNP-1 to examine ways by which the project can be completed more efficiently and at lower cost through careful planning and consultation with other interested utility entities during the period of preservation. BPA believes that the preservation period can be used to develop innovative, cost-efficient construction and scheduling techniques. It also provides an opportunity to use experience gained at other nuclear plants to maximum advantage. The benefits from the program should accrue to WNP-3, making the remaining construction more efficient.

5. Analysis by the Northwest Power Planning Council. The Northwest Power Planning Council has undertaken an analysis of Supply System project alternatives. They are examining various construction alternatives with respect to how these alternatives might affect the Council's recently adopted Northwest Conservation and Electric Power Plan. BPA has worked closely with the Council staff to provide all available information to aid in the Council's efforts. BPA expects the Council's work will contribute substantially to future decision-making regarding the Supply System projects. While the Council's concurrence in a decision to restart construction is not required, the Council has comprehensive knowledge of regional energy matters and the technical competence to provide important analytic information that will aid BPA and the other parties.

6. Provisions of Proposed BPA Rates. BPA's proposed rates were submitted to FERC on September 30, 1983. They reflect current construction plans regarding WNP-3; that is, proposed revenue requirements reflect a ramp down and preservation associated with a 3-year construction extension and payment by BPA and 70 percent of the costs associated with such extension once Supply System construction funds are depleted. These rates will be effective from November 1, 1983, to July 1, 1985. June 1, 1983, was the

last date on which major changes could be made in the rate case to reflect changes in Supply System project plans. The next opportunity to change BPA rates to reflect Supply System project costs is July 1, 1985.

SUMMARY OF RESULTS

The results of these studies cannot be viewed in isolation from other pervasive legal and institutional issues surrounding the Supply System projects. These other issues, which are not discussed in detail in this report, are of exceptional importance to any decision regarding the future construction schedule of WNP-3. It must be emphasized that we do not have unlimited time to settle these key issues regarding WNP-3. A restart of WNP-3 will take careful preparation and planning which must be completed in advance of actual restart. Therefore, legislative, judicial, or contractual resolution of Supply System difficulties is needed early to assure restart even by July 1985. Such issues, notwithstanding the resource economics results, analysis of rate impacts, and financial considerations discussed in this report, are instructive in determining the optimal course of action concerning the project.

Electric energy forecasts are sophisticated and educated projections about an uncertain future. At times, past forecasts have seriously over-estimated and at other times under-estimated energy growth. However, in recent years, with new forecast tools, forecasts have more closely tracked actual energy growth.

BPA considers it inappropriate to base actions required by expectations of future growth on a single projection, or to simply assume that energy consumption patterns of the recent past will continue out into the future. Instead, we now project a range of load growth outcomes which have various probabilities of occurrence. Using this range of load growth projections, BPA bases decisions on the need to buy future power from conservation, thermal plants, or renewable energy resources. This most recent BPA resource study of WNP-3 again takes this cautious approach of considering a range of forecasts. BPA's forecast foresees a range from a low of 1.3 percent growth in the next 20 years to a high of 2.6 percent. The Northwest Power Planning Council also defines a range of forecasts using slightly different limits. This forecasting approach aids in assessing the risks and costs of different resource acquisition strategies.

Analyses of the best available current information show that, given the Supply System's inability to finance its share of WNP-3, the construction extension approved earlier this year is the prudent and appropriate course of action. BPA's most recent analysis offers evidence that this decision allows the region maximum flexibility and avoids unacceptable near-term financial impact on BPA and the ratepayers of the Northwest. It will allow the region valuable time to resolve pending litigation and better determine the near-term economic and energy growth in the Northwest.

The results of the construction plans examined in this analysis suggest that substantial additional effort should be devoted to developing the most efficient possible plan for completing the project. BPA and the Supply System will pursue such efforts under the WNP-1 Preservation Enhancement Program.

KEY ANALYTIC RESULTS

The BPA analysis of these issues shows:

A. In the total resource picture for the Pacific Northwest, the WNP-3 project continues to be needed and is cost effective.

B. The resource economic analysis is basically neutral with regard to the choice between delay and early restart.

C. The obstacles to financing WNP-3 completion that were identified in BPA's May 26 report still exist. Specifically:

   (1) Conventional financing for WNP-3 cannot be achieved now, due to current legal and financial impediments.

(2) Financing the completion of WNP-3 out of BPA revenues is unacceptable because of the near-term burden it would place on the region's ratepayers and because of the financial risk it would place on BPA.

(3) There continues to be no reasonable likelihood of success in obtaining bank financing in the very near future.

OTHER ANALYTIC RESULTS

Economic

a. Under base case assumptions, a gradual restart of construction in July 1985 leading to a 3 1/2 year delay from the prior WNP-3 on-line date is somewhat less costly than early restart. However, changes in certain assumptions change this finding. In particular, if a fast construction pace is assumed, then construction restart in January 1984 is economically favored over restart in July 1985. In addition, the economic differences between early and later restart tend to be small.

b. Updated load/resource information based upon BPA's new long-term forecast shows that a delay of up to about 3 to 4 years can be accommodated without creating regional deficits.

c. Even under high load growth conditions, there is not an extreme economic penalty associated with a WNP-3 delay.

d. Delays of longer than 3 to 4 years begin to result in substantially higher total system costs, assuming base or high load projections develop.

e. The analyses continue to show that the loss of WNP-3 to the region would result in substantially increased costs due to purchases of higher cost replacement resources to meet long-term load growth, assuming the base or high load forecast.

f. The course of action with the most adverse regional result is one where construction continues at a rapid pace but later events result in project termination.

g. Under BPA's low load forecast, an unlikely occurrence, WNP-3 is not needed to serve regional loads.

h. Analyses of surplus firm power export cases show that a surplus firm power export arrangement is not decisive in determining either the cost effectiveness or the schedule of WNP-3. While not a major determinant of WNP-3 resource economics, a 1500 MW firm export sale for 15 years at 45 mills/kWh (1983 dollars) or 30 mills/kWh would yield a $3 billion or $1.3 billion net regional benefit. Even with substantial investment in additional interties, such a sale could be of substantial regional benefit. However, risks have yet to be fully and completely assessed.

Rates

a. Financing WNP-3 from revenues or short-term bank financing will result in higher rates over the near term when compared to conventional bond financing.

Financial

a. No significant changes in BPA's financial posture have occurred since BPA's study of May 26, 1983, except changes made to reflect BPA's revenue financing of WNP-2 construction costs and 70 percent of WNP-3 preservation costs.

b. Direct revenue financing of WNP-2 construction costs and 70 percent of WNP-3 preservation costs resulting from the Supply System's inability to finance has increased BPA's direct financial exposure to cost escalations associated with the Supply System plants.

c. BPA is unaware of any improvement in the factors which precluded conventional Supply System bond financing in May.

Context of the WNP-3 Restart Evaluation

In April and May of this year, BPA staff examined the system economics, rate impacts, and financial considerations surrounding various courses of action for WNP-3. The findings were documented in the "Analysis of Alternatives Related to WNP-3," May 26, 1983. Since that report, construction ramp-down on WNP-3 has commenced.

Options for construction restart continue to be examined. This report describes the system economics and rate impacts of various restart scenarios.

Actions on WNP-3, not WNP-1 or WNP-2, are the focus of this report. WNP-2 is ready for fuel loading, and previous studies have shown that it is the most economic of the projects to bring on-line as scheduled. Delay of WNP-2 could impose added costs and other problems on the project. For these reasons, WNP-2 is assumed to come on-line in February 1984 in all scenarios. WNP-1 is already in a preservation state and is scheduled for a delay of up to 5 years. No compelling reason to reduce the duration of the delay for WNP-1 has surfaced since the decision to delay was made. Because the scheduled construction restart date for WNP-1 is still several years away, a reevaluation of the optimal restart date is not necessary now but will be more valuable as current load and resource uncertainties become clearer with time. Accordingly, WNP-1 was assumed to come on-line in June 1991 for this evaluation. The exceptions were the scenarios used to evaluate a delay of more than 3 years for WNP-3. In these scenarios, the on-line date for WNP-1 was also delayed to make the scenarios internally consistent.

Alternatives Considered

The decisions that are likely to be necessary on WNP-3 in the near-term involve: (1) the date of construction restart; (2) the pace of construction after restart; and (3) the source of funding for the net-billed portion of the project.

1. Restart Dates: Restart dates of January 1984, July 1984, July 1985, and July 1987 were evaluated. January 1984 is the very earliest that construction could conceivably be restarted under some Congressional

initiative, and according to the Supply System it would yield a minimum 1-year delay in the on-line date to December 1987 if a fast construction pace was pursued, or a 1 1/2-year delay if a slower and more efficient construction pace were pursued. Project activities would not be fully ramped-down at the time of restart. July 1984 is perhaps a more realistic restart date under a Congressional initiative, yielding a 2-year delay in on-line date. Project activities would be fully ramped-down at that point. A July 1985 restart would yield a 3-year delay in on-line date with a fast construction pace and a 3 1/2-year delay with a slower pace. The July 1987 restart date was considered to test the economics and rate impacts of a 5-year delay in on-line date.

2. Construction Pace: Two construction paces were considered: the maximum pace and a slow, more economic, construction pace. Both paces were defined by the Supply System. Figure 1 depicts these construction paces and how they were associated with restart and on-line dates. Alternatives A, B, and C depict a maximum pace, while alternatives D and F depict a slower pace.

3. Source of Funds: Three sources of funds were considered: (1) conventional bond financing, assuming a 13 percent interest rate and a 35-year term; (2) bank financing through a new financing entity, assuming a 12.5 percent interest rate and a 12-year term; and (3) BPA revenue financing.

Analysis of Risk

Because future loads, interest rates, and the export market can vary significantly, the consequences of each alternative near-term decision on WNP-3 were forecast under a range of load forecasts, interest rates, and marketing assumptions. The consequences of an involuntary termination of WNP-1 and/or WNP-3 were also analyzed. Termination scenarios were analyzed for two reasons: (1) to examine whether alternative resources could be substituted for WNP-1 or WNP-3 at lower system cost; and (2) to estimate the economic and rate impacts of an involuntary termination.

To assess the influence of various risk factors on the economics of alternative decisions, probabilities were assigned to each load growth rate, and expected present values of system costs were computed for alternative decisions. BPA's new low, base, and high load forecasts were used. The probability that actual loads will exceed each forecast is estimated to be 90 percent for the low load forecast, 50 percent for the base forecast, and 10 percent for the high forecast.

All of the scenarios that were evaluated are listed in table 1.

TABLE 1

WNP-3 Restart, Scenarios Evaluated

Restart Scenario#	WNP-3 Restart Date	Construction Pace	Financing	Interest Rate[1/]	Discount Rate	Load Growth	Surplus Marketing[2/]	Conservation in Resource Plan	WNP-3 C.O.	WNP-1 C.O.
A-1	Jan. '84	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '87	June '91
A-2	Jan. '84	Fast	Conventional	15%	3%	Base	N.F.	LCMM	Dec '87	June '91
A-3	Jan. '84	Fast	Conventional	13%	3%	High	N.F.	LCMM	Dec '87	June '91
A-4	Jan. '84	Fast	Conventional	13%	3%	Low	N.F.	LCMM	Dec '87	June '91
A-5	Jan. '84	Fast	Conventional	13%	3%	Base	Firm	LCMM	Dec '87	June '91
A-6	Jan. '84	Fast	Bank	12.5%	3%	Base	N.F.	LCMM	Dec '87	June '91
A-1X	Jan. '84	Fast	Conventional	13%	3%	Base	N.F.	2500	Dec '87	June '91
A-1R	Jan. '84	Fast	Conventional	13%	3%	Base	N.F.	1000	Dec '87	June '91
B-1	July '84	Fast	Bank	12.5%	3%	Base	N.F.	LCMM	Dec '88	June '91
B-2	Julv '84	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '88	June '91
C-1	July '85	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '89	June '91
C 1a	July '85	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '89	June '93
C-2	July '85	Fast	Conventional	15%	3%	Base	N.F.	LCMM	Dec '89	June '91
C-3	July '85	Fast	Conventional	13%	3%	High	N.F.	LCMM	Dec '89	June '91
C-4	July '85	Fast	Conventional	13%	3%	Low	N.F.	LCMM	Dec '89	June '91
C-5	July '85	Fast	Conventional	13%	3%	Base	Firm	LCMM	Dec '89	June '91
C-6	July '85	Fast	Revenue	NA	3%	Base	N.F.	LCMM	Dec '89	June '91
C-7	July '85	Fast	Conventional	13%	3%	Low	Firm	LCMM	Dec '89	June '91
C-1X	July '85	Fast	Conventional	13%	3%	Base	N.F.	2500	Dec '89	June '91
C-1R	July '85	Fast	Conventional	13%	3%	Base	N.F.	1000	Dec '89	June '91
D-1	Julv '85	Slow	Revenue[3/]	NA	3%	Base	N.F.	LCMM	June'90	June '91
D-2	July '87	Slow	Conventional	13%	3%	Base	N.F.	LCMM	Dec '91	June '95
D-3	July '85	Slow	Conventional	13%	3%	Base	N.F.	LCMM	June'90	June '91

F-1	Jan '84	Slow	Conventional	13%	3%	Base	N.F.	LCMM	June'88	June '91
F-2	Jan '84	Slow	Conventional	13%	3%	High	N.F.	LCMM	June'88	June '91
T-1[4]	July '85	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '89	Out
T-2[4]	July '85	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Out	Out
T-3[4]	July '85	Fast	Conventional	13%	3%	High	N.F.	LCMM	Dec '89	Out
T-4[4]	July '85	Fast	Conventional	13%	3%	High	N.F.	LCMM	Out	Out
T-5[4]	July '85	Fast	Conventional	13%	3%	Low	N.F.	LCMM	Dec '89	Out
T-6[4]	July '85	Fast	Conventional	13%	3%	Low	N.F.	LCMM	Out	Out
T-7[4]	Jan. '84	Fast	Conventional	13%	3%	Base	N.F.	LCMM	Dec '87	Out
T-8	July '85	Fast	Conventional	13%	3%	Low	Firm	LCMM	Dec '89	Out
T-9	July '85	Fast	Conventional	13%	3%	Low	Firm	LCMM	Out	Out
T-10	July '85	Fast	Conventional	13%	3%	Base	Firm	LCMM	Dec '89	Out
T-11	July '85	Fast	Conventional	13%	3%	Base	Firm	LCMM	Out	Out
T-12[4]	July '85	Fast	Conventional	13%	3%	Base	N.F.	LCMM		June '91
T-2X	July '85	Fast	Conventional	13%	3%	Base	N.F.	2500	Out	Out
T-1X	July '85	Fast	Conventional	13%	3%	Base	N.F.	2500	Dec '89	Out
T-2R	July '85	Fast	Conventional	13%	3%	Base	N.F.	1000	Out	Out
T-1R	July '85	Fast	Conventional	13%	3%	Base	N.F.	1000	Dec '89	Out

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Footnotes

[1] Interest rates based on DRI forecasts and advice from Wertheim.

[2] N.F. = Non-firm. All of WNP-3's output is treated as secondary by the SAM export sales logic chosen for SAM's study. In the firm export scenarios, a 1500 MW firm export was assumed to be in place, with a 1500 MW expansion in intertie capacity.

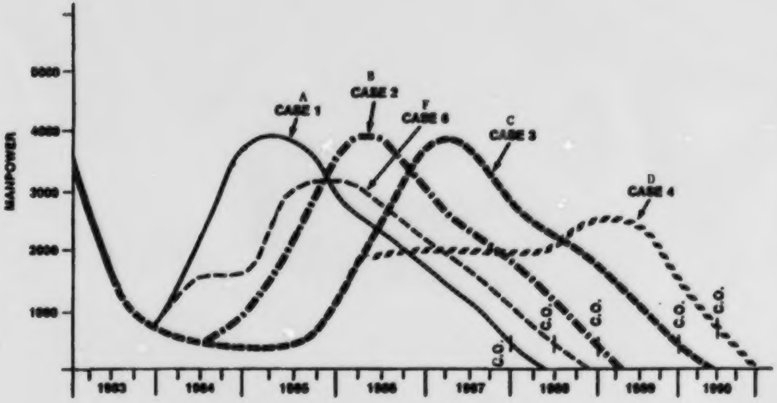
[3] In this scenario, part of WNP-3 construction costs are paid out of BPA revenues, and part are financed through conventional bonds.

[4] Subscenarios were evaluated for these termination scenarios. In one subscenario, termination was assumed to occur before restart. In the other subscenario, termination was assumed to occur after construction restart. Results for both subscenarios are shown in Tables 2 and 3.

FIGURE I

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PROJECT 3

TOTAL PROJECT MANPOWER PROFILES



C.O.: COMMERCIAL OPERATION

I RESOURCE ECONOMICS

As in previous evaluations, long-term system costs were forecast for each of the WNP-3 restart scenarios shown in table 1. System costs are reported in terms of present values in 1982 dollars, to allow consistent comparisons of scenarios.

Tables 2 and 3 present the economic evaluation results for each restart scenario. In the following pages, some of the most pertinent comparisons between scenarios are made. In these pages, as in the tables, scenarios are compared in terms of present value of 1982 $, in millions. Present values include the life-cycle costs of all resources added over the 20-year study horizon, plus the costs of the resources required to replace the initial resources at the end of their life cycles.

The basic procedures used for this economic evaluation are the same as were used for the May 26 report. ("Analysis of Alternatives Related to WNP-3.") This new evaluation incorporates more recent load forecasts and other new information. It also carries the evaluation of load growth uncertainty a step further and attempts to integrate firm export marketing potentials into the evaluation of WNP-3 restart alternatives. A section explaining the methods and assumptions used in the evaluation follows the section in which the pertinent comparisons are made.

Descriptions of the differences between BPA's studies and those conducted by the Council, and differences between the findings of this report and BPA's May 26 report are also included here, together with a summary of the Supply System project capital cost data used in the analyses.

TABLE 2

Present Value of Regional Costs
Including WNP Projects (Millions 1982 $)

Alternative:	A1	A2	A3	A4	A5	A6	A1X	A1R	B1	B2
Interest Rate:	13%	15%	13%	13%	13%	12.5%	13%	13%	12.5%	13%
Load Forecast:	Base	Base	High	Low	PM Expt	Base	Base	Base	Base	Base
WNP-3										
Re-start Date	Jan 84	Jan 84	Jan 84	Jan 84	Jan 84	Jan 84	Jan 84	Jan 84	Jul 84	Jul 84
Commercial Oper.	Dec 87	Dec 87	Dec 87	Dec 87	Dec 87	Dec 87	Dec 87	Dec 87	Dec 88	Dec 88
BPA 70%	3147	3335	3147	3147	3147	2786	3147	3147	2907	3285
Sunk	1843	1843	1843	1843	1843	1843	1843	1843	1943	1843
To Complete	1304	1492	1304	1304	1304	943	1304	1304	1064	1442
IOU 30%	909	909	909	909	909	909	909	909	1012	1012
WNP-1										
Commercial Oper.	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91
Total	4674	5001	4674	4674	4674	4674	4674	4674	4674	4674
Sunk	2351	2351	2351	2351	2351	2351	2351	2351	2351	2351
To Complete	2323	2650	2323	2323	2323	2323	2323	2323	2323	2323
WNP-2										
WPPSS Capital Costs	145	145	145	145	145	145	145	145	145	145
Subtotal	4681	5196	4681	4681	4681	4320	4681	4681	4674	4674
All Other Systems Costs										
Capital	27292	27292	56599	14901	30374	27292	27086	27405	27249	27249
Production	32730	32730	55416	28541	33264	32730	31550	33239	32661	32661
Secondary	(10880)	(10880)	(8230)	(12760)	(11125)	(10880)	(10929)	(10980)	(10859)	(10859)
Short-Term Purchase (outside Region)					226					
Curtailments	2023	2023	2336	444	1896	2023	1949	1847	2031	2011
Total Present Value of Regional	55846	56361	110802	38769	59316	55485	54337	56192	55626	56004

TABLE 2 (Continued)

Present Value of Regional Costs
Including the WNP Projects (Millions 1982 $)

Alternative:	C1	C1a	C2	C3	C4	C5	C6	C7	C1X	C1R
Interest Rate:	13%	13%	15%	13%	13%	13%	Revenue	13%	13%	13%
Load Forecast:	Base	Base	Base	High	Low	Base Fm Expt	Base	Low Fm Expt	Base	Base
WNP-3										
Re-start Date	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85	Jul 85
Commercial Oper.	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89	Dec 89
BPA 70%	3273	3273	3466	3273	3273	3273	2761	3273	3273	3273
Sunk	1843	1843	1843	1843	1843	1843	1843	1843	1843	1843
To Complete	1430	1430	1623	1430	1430	1430	918	1430	1430	1430
IOU 30%	1038	1038	1038	1038	1038	1038	1038	1038	1038	1038
WNP-1										
Commercial Oper.	Jun 91	Jun 93	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91	Jun 91
Total	4674	4705	4674	4674	4674	4674	4674	4674	4674	4674
Sunk	2351	2351	2351	2351	2351	2351	2351	2351	2351	2351
To Complete	2323	2354	2650	2323	2323	2323	2323	2323	2323	2323
WNP-2										
WPPSS Capital Costs	145	145	145	145	145	145	145	145	145	145
Subtotal	4936	4967	5456	4936	4936	4936	4424	4936	4936	4936
All Other Systems Costs										
Capital	27185	27070	27186	56477	17713	30158	27186	21193	26970	27277
Production	32617	32496	32617	55503	28385	33120	32617	30269	31424	33112
Secondary	(10837)	(10769)	(10837)	(8178)	(12737)	(11099)	(10837)	(10872)	(10869)	(10926)
Short-Term Purchase (outside Region)						486				
Curtailments	2042	2055	2042	2382	419	1908	2042	1082	1982	1876
Total Present Value of Regional System Costs.	55944	55819	56464	111120	38716	59609	55432	46608	54443	56275

TABLE 2 (Continued)

Present Value of Regional Costs
Including the WNP Projects (Millions 1982 $)

Alternative:	D1	D2	D3	F1	F2
Interest Rate:	Revenue	13%	13%	13%	13%
Load Forecast:	Base	Base	Base	Base	High
WNP-3					
Re-start Date	Jul 85	Jul 87	Jul 85	Jan 84	Jan 84
Commercial Oper.	Jun 90	Jun 91	Jun 90	Jun 88	Jun 88
BPA 70%	2946	3342	3229	3146	3146
Sunk	1843	1843	1843	1843	1843
To Complete	1103	1499	1386	1303	1303
IOU 30%	989	1068	989	911	911
WNP-1					
Commercial Oper.	Jun 91	Jun 95	Jun 91	Jun 91	Jun 91
Total	4674	4734	4674	4674	4674
Sunk	2351	2351	2351	2351	2351
To Complete	2323	2383	2323	2323	2323
WNP-2					
WPPSS Capital Costs	145	145	145	145	145
Subtotal	4560	5115	4843	4682	4682
All Other Systems Costs					
Capital	27125	27502	27125	27241	56622
Production	32560	32170	32560	32710	55455
Secondary	(10820)	(10772)	(10820))	(10825)	(8260)
Curtailments	2035	2096	2035	2361	2361
TOTAL	55460	56111	55743	55830	110860

TABLE 3
Present Value of Regional System Costs
Including the WPPSS Projects (Millions 1982 $)
Termination Scenarios[1]

	Base Loads WNP-1 Out T1	Base Loads WNP-1&3 Out T2	High Loads WNP-1 Out T3	High Loads WNP-1&3 Out T4	Low Loads WNP-1 Out T5	Low Loads WNP-1&3 Out T6	Base Loads WNP-1 Out T7
All Other System Costs							
Capital	28759	30634	57824	59078	17921	18100	28936
Production	34509	36380	57173	59638	27766	28081	34639
Secondary	(10700)	(10666)	(7461)	(5941)	(11790)	(11553)	(10818)
Curtailments	1952	1954	2489	2232	887	1053	1984
Supply System Capital Costs							
WNP-3		Termination Before Restart					
BPA	1430		1430		1430		1304
IOU	1038		1038		1038		909
Costs with Termination	-	181	-	181	-	181	-
WNP-1	0	0	0	0	0	0	0
WNP-2	145	145	145	145	145	145	145 Total
57133	58628	112638	114268	37397	36007	57099	
		Termination After Restart[2]					
WNP-3							
(Costs Through Sept. 88)							
BPA	1430	1098	1430	1098	1430	1098	1304
IOU	1038	797	1038	797	1038	797	909
(Costs through Dec. 88)							
WNP-1	1439	1439	1439	1439	1439	1439	1439
WNP-2	145	145	145	145	145	145	145
Total	58572	61781	114077	117421	38836	39088	58538

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[1] For scenarios T-1 through T-6, it is assumed that a decision has been made to put WNP-3 on a July '85 restart schedule, with an anticipated on-line date of December '89, and that termination occurs before construction is restarted on either project. In T7, it is assumed that WNP-3 is restarted in January '84, and brought on-line in December '87, while WNP-1 is terminated before it is restarted.

[2] Costs through December 1988 are assumed to be incurred on WNP-1 and 3 before they are terminated.

TABLE 3 (Continued)
Present Value of Regional System Costs
Including the WNP Projects (Millions 1982 $)
Termination Scenarios1/

	Firm Export				
	Low Loads WNP-1 Out T8	Low Loads WNP-1&3 Out T9	Base Loads WNP-1 Out T10	Base Loads WNP-1&3 Out T11	Base Loads WNP-3 Out T12
All Other System Costs					
Capital	22662	27198	32128	33410	28713
Production	26839	25186	36444	38628	34464
Secondary	(10626)	(10518)	(11824)	(11715)	(10736)
Curtailments	1390	1435	1915	1979	1924
Supply System Capital Costs					
WNP-3	Termination Before Restart				
BPA	1430		1430		
IOU	1038		1038		
Costs with Termination	--	181	--	181	181
WNP-1	0	0	0	0	2323
WNP-2	145	145	145	145	145
Total	42878	43627	61276	62628	57014
	Termination After Restart2/				
WNP-3 (Costs Through Sept. 88)					
BPA					1098
IOU					797
WNP-1					2323
WNP-2					145
Total					58728

	2500 MW & 1000 MW Conservation			
	Base Loads WNP-1 Out T1X	Base Loads WNP-1&3 Out T2X	Base Loads WNP-1 Out T1R	Base Loads WNP-1&3 Out T2R
All Other System Costs				
Capital	26936	28566	29078	30849
Production	32637	33818	34933	36588
Secondary	10667)	(10738)	(10693)	(10517)
Curtailments	2098	2423	1828	1956
Supply System Capital Costs				
WNP-3	Termination Before Restart			
BPA	1430		1430	
IOU	1038		1038	
Costs with Termination	-	181	-	181
WNP-1	0	0	0	0
WNP-2	145	145	145	145
Total	53617	54395	57759	59202

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Comparison #1: What is the most economic construction restart date and construction pace given base load forecast, 13 percent conventional bond financing, and no additional long-term firm export sales?

Regional Economics

Alternative	A1	F1	B2	C1	D3
Present Value System Costs	55846	55830	56004	55944	55743
Restart Date	Jan 84	Jan 84	Jul 84	Jul 85	Jul 85
Commercial Operation Date	Dec 87	Jun 88	Dec 88	Dec 89	Jun 90
Load Forecast	Base	Base	Base	Base	Base
Construction Pace	Fast	Slow	Fast	Fast	Slow
Benefit, Relative to C-1	98	114	-60	0	201

This comparison indicates that the two slower construction pace options (D3 and F1) are the lowest cost. This is because the Supply System indicates that the slower construction pace is most efficient. The lowest cost option is a July 1985 restart date, with a 3 1/2 year delay in commercial operation and a slow construction pace (D3). The present value difference between this option and a January 1984 restart (F1) is small ($87 million). If a fast construction pace is assumed, early restart (A1) is favored over delay (C1), by $98 million. This reversal is a result of the Supply System capital cost estimates, which show a smaller delay cost penalty if a slow construction pace is used. Delaying the on-line date up to 3 1/2 years, (D3) requires only minor acceleration of the development of conservation and renewable resources.

Comparison #2: The above cases have tested 1-, 2-, and 3-year delay scenarios. Would a delay of more than 3 years be more economic, assuming base load growth?

Regional Economics

Alternatives	Cla	D2
Present Value System Costs	55,819	56,111
Restart Date	Jul 85	Jul 87
Commercial Operation Date	Dec 89	Dec 91
Load Forecast	Base	Base
WNP-3 Delay in Years	3	5
WNP-1 Delay in Years	7	9
Benefit, Relative to Cla	0	-292

The 3-year delay is more economic than a 5-year delay, under base case assumptions. For this comparison, the on-line date for WNP-1 is delayed in tandem with the on-line date for WNP-3, because otherwise a 5-year delay in WNP-3 would bring it on-line after WNP-1.

Comparison #3: Do the above conclusions change when the financing rate assumption is increased to 15 percent?

Regional Economics

Alternatives	A2	C2
Present Value System Costs	56,361	56,464
Restart Date	Jan 84	Jul 85
Commercial Operation Date	Dec 87	Dec 89
Load Forecast	Base	Base
Benefit, Relative to C2	103	0

This comparison indicates that increasing the interest rate assumption to 15 percent does not change the cost/benefit relationship between restart alternatives. The higher interest rate does, however, increase total system costs to the region for any alternative.

Comparison #4: What is the most economic restart date when the high load forecast is substituted for the base load forecasts?

Regional Economics

Alternatives	A3	C3	F2
Present Value System Costs	110,802	111,120	110,860
Restart Date	Jan 84	Jul 85	Jan 84
Commercial Operation Date	Dec 87	Dec 89	Jun 88
Load Forecast	High	High	High
Construction Pace	Fast	Fast	Slow
Benefit, Relative to C3	318	0	260

These alternatives assume the July 1983 high load forecast with a 2.6 percent[1] average annual load growth rate. Assuming the high load forecast causes forecasted total system costs to be approximately double the costs of the alternatives using the base load forecasts. This is caused by the need to build and operate 7200 megawatts of additional new thermal capacity under the high forecast, in addition to an aggressive development of conservation and renewable resources. Because delay forces accelerated development of more expensive resources, the earliest restart is favored by a larger margin than in the base forecast, assuming a fast construction pace. The delay case with slow construction (D) was not evaluated under the high load assumptions, but results suggest that earliest restart would be slightly favored over that option assuming high loads.

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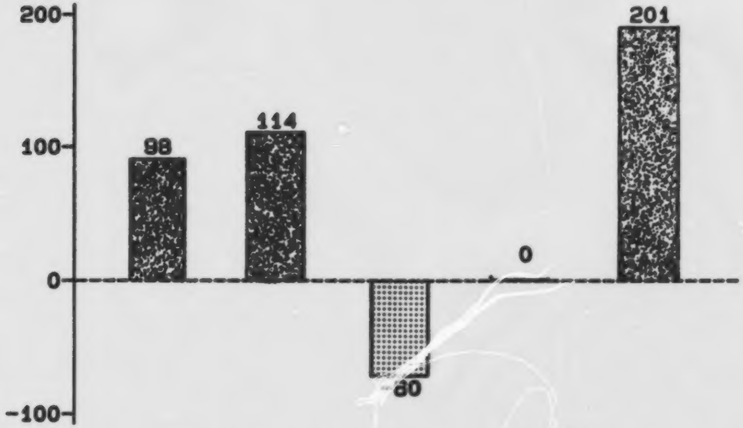
[1] Until this year, load growth rates had been reported starting in a base year of 1980. The 1.8 percent rate is computed from a base year of 1983. The growth rate of the new forecast, using a 1980 base year, is 1.4 percent.

PRESENT VALUE TOTAL SYSTEM BENEFIT DIFFERENCES REFERENCED TO 3 YEAR DELAY



SCENARIO	A1	F1	B2	C1	D3
RESTART DATE	Jan 84	Jan 84	Jul 84	Jul 85	Jul 85
C.O. DATE	Dec 87	Jun 88	Dec 88	Dec 89	Jun 90
CONSTR DATE	FAST	SLOW	FAST	FAST	SLOW
YEARS OF DELAY	1	1-1/2	2	3	3-1/2

Comparison #5: Does the economic restart date change under the low load forecast?

Regional Economics

Alternatives	A4	C4
Present Value System Costs	38,769	38,716
Restart Date	Jan 84	Jul 85
Commercial Operation Date	Dec 87	Dec 89
Load Forecast	Low	Low
Benefit, Relative to C4	-55	0

Under low loads, delay has a slight economic advantage over immediate restart, even assuming a fast construction pace. Total present value of system costs is also much less than under the base forecast.

Comparison #6: What is the relationship between surplus firm power export sales potential and the restart date for WNP-3?

Regional Economics

Alternatives	A5	C5	A1	C1
Present Value System Costs	59,316	59,609	55,846	55,944
Restart Date	Jan 84	Jul 85	Jan 84	Jul 85
WNP-3 Commercial Operation	Dec 87	Dec 89	Dec 87	Dec 89
Load Forecast	Base	Base	Base	Base
Plants Terminated	None	None	None	None
Firm Export	Yes	Yes	No	No
Intertie Expansion	Yes	Yes	No	No
Firm Export Revenues	6,468	6,468	0	0
Net System Costs	52,848	53,141	55,846	55,944
Benefit, Relative to C1	+3096	+2803	-98	0
Benefit, Relative to C5	293	0	-2705	-2803

Assumptions for this comparison were that a 1500 MW surplus firm power export sale for 15 years could be made, a 1500 MW intertie expansion would be in place in 1990, and the base load forecast. Assuming a 45 mill per kilowatthour price for a 1500 MW surplus firm power export from 1985 to 2000, the sale would yield revenues of $6.468 billion, on a present value basis. For this comparison, the long-term firm sale was assumed to be in place, whether WNP-3 was delayed 1 or 3 years. Hence, revenues from the firm sale are the same in both A5 and C5. Assuming the availability of some short-term firm purchases at 50 mills/kWh, the firm sale could be met without building any new large thermal plants, whether or not WNP-3 is delayed, assuming base loads. The C5/A5 comparison indicates that the economic case for early restart is strengthened if a surplus firm power sale is assumed to be in place. The economic penalty for delay with fast construction pace is estimated at $293 million in this case, vs. $98 million with no sale. This is primarily because delay would force acceleration of the development of new resources in order to meet the sale and probably some short-term purchases of power at high cost in a couple of years.

The sale would require some resources to be developed earlier, but the A5/A1 comparison suggests that a $3 billion net benefit would be realized above the cost of those additional resources assuming a 45 mill export price. The cost of the intertie expansion itself would absorb some of this benefit. The net benefit falls to $1.3 billion if a 30-mill firm sale price is assumed.

The C5/C1 comparison indicates that a 3-year delay of WNP-3 does not seriously impair the economics of a firm power sale, even though some short-term purchases would likely be required to support the sale in the late 1980's.

Comparison #7: Is the economic restart date changed when a short-term bank financing scenario is assumed?

Regional Economics

Alternatives	A6	B1
Present Value System Costs	55,485	55,626
Restart Date	Jan 84	Jul 84
Commercial Operations Date	Base	Base
Benefits, Relative to A6	0	-141

These alternatives assume the private bank financing scenario at 12.5 percent interest, for a 12-year term. This comparison confirms that the choice of restart date is not very sensitive to the choice between conventional or bank financing.

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Comparison #8: Given the base load forecast, is terminating WNP-1 and/or WNP-3 before restart in the best economic interests of the region?

Regional Economics

Alternatives	C1	T1	T2	T12
Present Value System Costs	55,944	57,133	58,628	57,014
WNP-3 Restart Date	Jul 85	Jul 85	Out	Out
WNP-3 Commercial Operation Date	Dec 89	Dec 89	Out	Out
Load Forecast	Base	Base	Base	Base
Plants Terminated	None	WNP-1	WNP-1&3	WNP-3
Benefits, Relative to C1	0	-1189	-2684	-1070

This analysis indicates that terminating WNP-1, and/or 3, replacing the energy by accelerating the development of conservation and renewable resources, and meeting future load growth with energy from new thermal plants would cost the region significantly more than completing the projects. The estimated system cost increase is over $1 billion for termination of either WNP-1 or WNP-3 (T1 or T12), and $2.7 billion for terminating both projects.

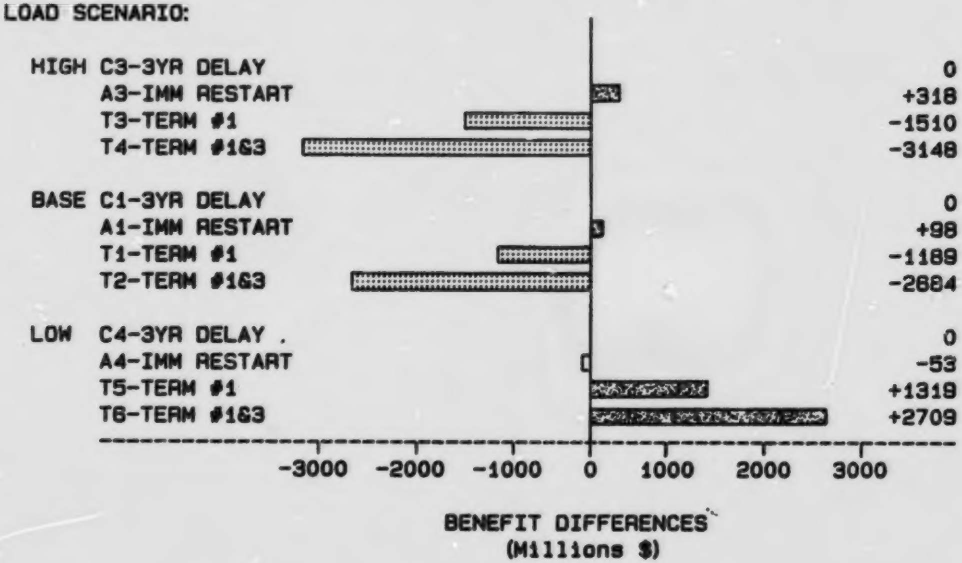
Comparison #9: Given the base load forecast, what are the economic consequences of termination of WNP-1 or 3 after construction restart?

Regional Economics

Alternatives	C1	T1b	T2b	T12b
Present Value System Costs	55,944	58,572	61,781	58,728
WNP-3 Restart Date	Jul 85	Jul 85	Out	Out
WNP-3 Commercial Operation Date	Dec 89	Dec 89	Out	Out
Load Forecast	Base	Base	Base	Base
Plants Terminated	None	WNP-1	WNP-1&3	WNP-3
Benefits, Relative to C1	0	-2,628	-5,837	-2,784

This comparison indicates that the costs to the region of restarting construction of the plants and then being unable to complete them can be very great; nearly $3 billion for one plant, and nearly $6 billion for WNP-1&3.

PRESENT VALUE TOTAL SYSTEM BENEFIT DIFFERENCES
REFERENCED TO 3 YEAR DELAY



Comparison #10: Given the high load forecast, is terminating WNP-1 or 3 in the best economic interests of the region?

Regional Economics

Alternatives	C3	T3	T4
Present Value System Costs	111,120	112,638	114,268
WNP-3 Restart Date	Jul 85	Jul 85	Out
WNP-3 Commercial Operation Date	Dec 89	Dec 89	Out
Load Forecast	High	High	High
Plants Terminated	None	WNP-1	WNP-1&3
Benefits, Relative to C3	0	-1,518	-3,148

Under the high load growth assumptions, new thermal resources must be substituted for WNP-1 & 3 almost as soon as they can be brought on-line, because the cost-effective conservation and renewable resource potential is forecast to be quickly exhausted. Consequently, the economic penalty for termination is greater under the high forecast than under the base forecast; $1.5 billion for WNP-1 and $3.1 billion for WNP-1 & 3.

Comparison #11: Given the low load forecast, is terminating WNP-1 and/or WNP-3 in the best interest of the region?

Regional Economics

Alternatives	C4	T5	T6
Present Value System Costs	38,716	37,397	36,007
WNP-3 Restart Date	Jul 85	Jul 85	Out
WNP-3 Commercial Operation Date	Dec 89	Dec 89	Out
Load Forecast	Low	Low	Low
Plants Terminated	None	WNP-1	WNP-1&3
Benefits, Relative to C4	0	+1,319	+2,709

Under the low load forecast, and assuming no long-term firm export, there are sufficient resources available to replace WNP-1 & 3 at less than their incremental costs, through the end of the study horizon. Consequently, termination of WNP-1 is forecast to yield present value savings of $1.3 billion under these assumptions. It should be noted that the low forecast, like the high forecast, is very unlikely. There is an estimated 90 percent chance that actual loads will be greater than the low forecast. Forecasts of systems cost impacts using the low forecast also appear to have more inherent uncertainty, because assumptions about load growth after the 20-year study horizon take on particular significance in this case, as do estimates of the costs of new resources far in the future.

Comparison #12: Assuming a low load forecast, a 1500 MW surplus firm power export, a 1500 MW intertie expansion, and the July 1985 restart scenario, is terminating WNP-1 or WNP-3 in the best economic interests of the region?

Regional Economics

Alternatives	C7	T8	T9
Present Value System Costs	46,608	46,746	47,587
Restart date	Jul 85	Jul 85	Out
Commercial Operation Date	Dec 89	Dec 89	Out
Load Forecast	Low	Low	Low
Plants Terminated	Neither	WNP-1	Both
Benefits, Relative to C7	0	-138	-979

This comparison was made because there is good reason to believe that a long-term firm sale would be made if the low load forecast were expected. Therefore, this comparison may yield the more realistic view of the economics of termination under the low forecast. The C7/T8 comparison indicates that it is not economic to terminate one plant, under the firm export assumption. The T9 result indicates that terminating WNP-3 after WNP-1 is terminated would add over $800 million to regional system costs.

As in the previous comparison, these estimates require assumptions about conditions far into the future, making the estimates highly uncertain.

Comparsion #13: What are the economics of immediate restart vs. delay vs. termination, if new conservation supply is reduced by 25 percent, assuming base load growth?

Regional Economics

Alternatives	A1R	C1R	T1R	T2R
Present Value System Costs	56,192	56,275	57,759	59,202
WNP-3 Restart Date	Jul 84	Jul 85	Jul 85	Out
WNP-3 Commercial Operation Date	Dec 87	Dec 89	Dec 89	Out
Load Forecast	Base	Base	Base	Base
Plants Terminated	None	None	WNP-1	WNP-1&3
Benefits, Relative to C1R	83	0	-1,484	-2,927

This comparsion was evaluated to test the effects of uncertainty in the supply of new conservation. BPA's best estimate of this supply is 1300 average MW, excluding savings from existing programs. The supply was reduced to 1000 average MW for this test. This reduction had virtually no effect on the choice between early and later restart (A1R vs. C1R).

However, the reduced conservation increases the costs of terminating the projects because new coal plants must be substituted earlier.

Comparison #14: What are the economics of immediate restart vs. delay vs. termination, if new conservation supply is doubled, assuming base loads?

Regional Economics

Alternatives	A1X	C1X	T1X	T2X
Present Value System Costs	54,337	54,443	53,617	54,395
WNP-3 Restart Date	Jan 84	Jul 85	Jul 85	Out
WNP-3 Commercial Operation Date	Dec 87	Dec 89	Dec 89	Out
Load Forecast	Base	Base	Base	Base
Plants Terminated	None	None	WNP-1	WNP-1&3
Benefits, Relative to C1X	106	0	826	48

The effects of increasing the conservation supply from 1300 average MW to 2500 average MW at the same cost was also tested. BPA believes 2500 MW to be far in excess of the actual supply, but this test provides an indication of the importance of such estimates. Again, this change had little effect on the choice between early and delayed restart. However, the large addition to conservation supply caused termination of WNP-1 to appear economic, with an $826 million cost reduction. Terminating WNP-3 after WNP-1 was not economic under these assumptions, because the additional conservation supply is mostly exhausted by replacing WNP-1.

Comparison #15: What is the expected value of the economic consequences of various dispositions of WNP-3?

A decision to restart WNP-3 earlier rather than later will have different economic consequences, depending on the load growth that actually occurs in the future. One way of addressing the uncertainty in load growth is to forecast the economic consequences for a range of load forecasts, as reported above. A standard way of taking this analysis of uncertainty a step further is to assign probabilities to the different load forecasts and then to compute an expected present value of the economic consequences. The expected present value is essentially an average of the economic consequences over the whole range of load forecasts, weighted by the probability of each forecast being equaled or exceeded. Expected values were computed for the January 1984 restart, the July 1985 restart, and the two termination cases, as shown below.

Regional Economics

Alternatives	A1/A3/A4	C1/C3/C4	T1/T3/T5	T2/T4/T6
Expected Present Value System Costs	67,661	67,802	68,308	68,946
Restart Date	Jan 84	Jul 85	Jul 85	Out
WNP-3 Commercial Operation Date	Dec 87	Dec 89	Dec 89	Out
Plants Terminated	None	None	WNP-1	WNP-1&3
Benefits, Relative to C1/C3/C4	141	0	-506	-1,144

This analysis of the present value of the expected costs confirms that termination of either plant would impose significant costs on the region, and that early restart is slightly more economic if a fast construction pace is assumed.

Comparison #16: What is the effect of counting consumer AFUDC on WNP-3 costs that are recovered in rates before the project comes on-line?

Some of the incremental costs of the net-billed share of WNP-3 will be recovered through rates before the project comes on-line. In the present value analysis, these costs are simply discounted back to 1982, using the 3-percent real discount rate plus the inflation rate. By contrast, dollars spent by IOU participants before the on-line date are assumed to accumulate interest up to the on-line date at a real rate of 5.8 percent to account for their "Allowance for Funds Used During Construction" (AFUDC). Capital costs including AFUDC are then put into the rate base, and capital revenue requirements in each subsequent year are discounted back to 1982, using the 3-percent real discount rate plus inflation. The AFUDC boosts the present value of IOU expenditures relative to expenditures on the net-billed share. This approach simulates as nearly as practicable how costs would actually be recovered from ratepayers, and applies the real discount rate consistently to all costs.

However, it has been argued that ratepayers are effectively "loaning" money to the Supply System by paying some Supply System costs before the on-line date. It is further argued that an AFUDC rate should be charged on these payments, as it is on IOU costs. A high consumer AFUDC rate is sometimes proposed, since consumers are presumed to regard Supply System projects as high risk investments.

The theoretical arguments over whether some consumer interest rate or AFUDC rate should be charged are complex. The purpose of this comparison was simply to estimate how significant consumer AFUDC would be if it were included in the WNP-3 restart evaluation. For this test, a 5.8 percent real consumer AFUDC rate was applied to all incremental WNP-3 costs recovered in rates before the on-line date. The capital cost increments due to consumer AFUDC are shown below. Costs are in millions of 1982 dollars, present value.

Regional Economics

Alternative	A1	A6	B2	C1
Financing	Conventional	Bank	Conventional	Conventional
Restart Date	Jan 84	Jan 84	Jul 84	Jul 85
On-line	Dec 87	Dec 87	Dec 88	Dec 89
Net-billed Capital[1]	1304	943	1442	1430
Total Net System Cost	54,846	55,485	56,004	55,944
Consumer AFUDC	16	9	25	31
Total Net System Cost w/Consumer AFUDC Cost	55,862	55,494	56,029	55,975

This comparison shows that including consumer AFUDC raises the total present value of capital costs only slightly. The comparison of A1, B2, and C1 above shows that adding consumer AFUDC also very slightly enhances the economic case for early restart. These results indicate that counting or not counting consumer AFUDC does not have a significant bearing on the economics of WNP-3 restart.

Comparison #17: What is the economic construction restart date and construction pace given base load forecast, conventional bond financing, no additional long-term firm export sales, and including the IOU AFUDC on their sunk costs on WNP-3?

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[1] Present value of incremental costs, without consumer AFUDC.

AFUDC Difference from F1	-13	0	+14	+42	+53

Regional Economics

Alternatives	A1	F1	B2	C1	D3
Present Value System Costs	55,833	55,830	36,018	55,986	55,796
Restart Date	Jan 84	Jan 84	Jul 84	Jul 85	Jul 85
Commercial Operation Date	Dec 87	Dec 88	Dec 88	Dec 89	Jun 90
Load Forecast	Base	Base	Base	Base	Base
Constrution Pace	Fast	Slow	Fast	Fast	Slow
Benefit, Relative to C1	+153	+156	-32	0	+190

It has been argued that delaying the restart of WNP-3 imposes additional costs on ratepayers, because AFUDC will continue to accumulate on the $725 million in IOU sunk costs that are not already included in the rate base. BPA has chosen not to include these costs, because they are strictly an artifact of the difference between the IOU AFUDC rate, which averages 11.2 percent, and the nominal discount rate used for present value analysis, which is 9.2 percent and because BPA believes that sunk costs in general are not relevant to the decision as to when to restart WNP-3. Also, it is not clear that the IOU's will not be able to include any of their sunk costs in their rate base before WNP-3 comes on-line.

However, this comparison was added to the analysis to show the impact of including AFUDC on sunk costs. As the comparison shows, adding this AFUDC shifts the economic results slightly towards early restart, but the 3-year delay remains most economic under the slow construction pace assumption.

Methods and Assumptions Used to Forecast System Cost Impacts

Total regional net system costs were estimated for each WNP-3 alternative. The general method used to forecast costs was the same as was used for the May 26, 1983, "Analysis of Alternatives Related to WNP-3". To provide a consistent basis for comparing alternatives, system costs were discounted back to present value in 1982 dollars. Because there is a great deal of uncertainty about future load growth rates, forecasts of system cost impacts were made under low, base, and high load growth assumptions. A range of assumptions about financing, export sales, interest rates, and alternative resource supply and costs were also tested. Each category of net system costs was forecasted as described below.

a. WNP-3 Capital Costs. Costs to complete WNP-3 on various schedules were estimated by Supply System staff. Construction cash flows were converted to bond schedules in the alternatives in which bond financing was assumed. The cash flows and resulting present values are shown later in this report. BPA's revenue requirement program was used to estimate nominal streams of capital revenue requirements from the schedules of bond sales. A 13 percent interest rate was assumed for new bond sales if such sales could be made. The interest rate assumption was based on advice from BPA's financial advisor, Wertheim Associates. An 8 percent inflation rate was assumed for capital costs, with a 6 percent general inflation rate. The streams of revenue requirements were discounted back to present value in constant 1982 dollars. Capital cost estimates included increases due to ramping-up and ramping-down expenses, plus site preservation costs.

Because there is considerable uncertainty about the interest rate on eventual bond sales, sensitivity analysis was conducted assuming a 15 percent future interest rate on the net-billed share, with no change in the 6 percent inflation rate.

b. Other Resources' Capital Costs. Delay or termination of WNP-3 would require some resources to be developed earlier. Delay or termination increases the present value of the capital costs of these resources.

Counterbalancing this effect is the reduction in the present value of the cost of the resources that would replace Supply System projects at the end of the

Supply System projects' lives, since delay of Supply System projects would cause these replacement resources to be delayed.

Both of these counterbalancing effects on the capital costs of other resources were estimated using the System Analysis Model (SAM). Present values of capital costs were estimated by SAM for each alternative, using the mixes of other resources specified by the least-cost mix model (LCMM). The Supply System projects were assumed to be replaced by other large thermal plants at the end of their useful lives under the base and high load forecasts and by conservation and renewable resources under the low load forecast.

SAM is a model that simulates the operation of the regional power system over a 20-year planning horizon, using a prespecified mix of generating and conservation resources. SAM predicts the production costs (O&M and fuel), capital costs, and export revenues for the regional system, given a particular mix of resources. SAM also forecasts the reliability of the system, in terms of average megawatts of load curtailed.

c. System Production Costs. Production costs are the costs of operating generating resources, including fuel and nonfuel O&M costs, both fixed and variable, and including the production costs of the WNP projects. Delaying WNP-3 projects has two counterbalancing effects on system production costs: delaying the project delays its stream of production costs, thereby reducing their present value; and the absence of generation from WNP projects tends to force other thermal resources to operate more often, thereby increasing their costs. SAM was used to estimate both of these effects on production costs.

d. Secondary Revenues. Delay or termination of WNP projects would reduce the amount of firm power available for export, and hence would reduce revenues from export. SAM was used to predict the magnitude of this loss in revenues. The following assumptions are used in SAM to estimate export revenues:

-- The highest cost resources currently operating are exported.

-- When the intertie is not full, the export price for thermal resources is equal to their fully-allocated costs, up to a ceiling of 30 mills per kWh, and the price for hydro exports is 20 mills (approximately

BPA's standard rate). The 30 mill figure is a current estimate of the maximum market price for nonfirm export sales.

-- When the intertie is full, the export price for thermal resources is their incremental cost plus 2 mills, and for hydro the price is 9 mills (representing the spill rate) for energy the system would otherwise spill, and 20 mills for energy which could be stored.

-- At these prices, it is assumed that Pacific Southwest utilities will always be willing to buy power up to the intertie capacity.

Under these assumptions, the export price declines as new increments of firm surplus supply with low or no variable cost are added to the system.

A firm export scenario was also examined. In this scenario, a new 1500 MW firm export was assumed to exist between 1985 and 2000, with a 1500 MW intertie expansion in 1990. A price of 45 mills/kWh was also assumed in this scenario.

e. Curtailment Costs. The analysis suggests that firm deficits can probably be avoided even if WNP-3 undergoes a multiyear delay. Even so, delay of WNP-3 could cause some small increase in the probability of load curtailment, primarily to the interruptible quartile of DSI load. The cost of curtailing interruptible load was set at 22 mills per kWh. There is clearly a great deal of uncertainty and sensitivity about the cost of load curtailment. The value was set roughly equal to the price paid for energy by DSI customers. Arguments can be made for much higher and much lower values. However, it became clear from these SAM studies that use of alternative estimates of the cost of curtailment, within any reasonable range, would not significantly affect the conclusion of the evaluation.

f. Resource Shifts in Response to WNP-3 Schedule Changes. Delay in the construction of WNP-3 is likely to require only minor adjustment in the schedules of new resource additions, assuming the low or base load forecast. Assuming the high forecast, or base loads with a 1500 MW firm export, more significant acceleration of the development of new resources would be required. Likewise, termination of a plant under base loads would require significant acceleration of conservation and renewable resources in the 1990's, and development of additional new thermal capacity around the year 2000. These resource shifts were forecast using BPA's Least Cost Mix Model (LCMM).

Differences Between the Council's and BPA's WNP-3 Restart Studies

The following differences between BPA's WNP-3 restart study and the analysis being performed by the Council staff have been gleaned mostly from informal staff contacts. Other differences are likely to become apparent as more of the Council's work is finalized and released.

NUCLEAR FUEL COSTS

Difference: BPA uses 15-year levelized fuel costs from the 1981 Supply System 10-year fuel plan, escalated at a negative real escalation rate of 2.3 percent real as forecast by Data Resources, Inc. (DRI).

The Council is using a fuel cost derived from WPPSS fuel contracts for the life of contracts and assuming a market value for fuel beyond that escalated annually at 1.5 percent real.

Effect on the Studies: The Council's forecast of fuel escalation will tend to increase the project's cost for their WNP-3 cost effectiveness test and will tend to favor delay.

CAPITAL COSTS

Difference: The Council assumes the study period for the influencing of WNP-3 decisions to start in January 1984. Any costs incurred before that period are considered sunk. Also any costs that occur after January 1984 that are classified as demobilization costs, are also considered sunk costs and are not included in the cost to complete.

BPA, on the other hand, considers costs starting in July 1983 in the costs to complete including demobilization costs.

Effect on the Studies: The Council's assumptions will tend to decrease the incremental cost for WNP-3. BPA's assumption makes our results consistent with our May 26, 1983, study results but somewhat overestimates incremental capital costs.

CONSERVATION SUPLY

Difference: The council assumes a substantially greater supply of potential new conservation and greater flexibility to accelerate its development, than does BPA.

Effect on the Stuies: This will tend to favor delay and make termination appear less costly.

SCENARIO DEFINITION

Difference: The council staff are using their strategic planning model to optimally schedule Supply System projects for each forecast within their range of load forecast, assuming foreknowledge of loads. BPA's analysis forecasts the consequences of various fixed restart dates also under a range of load growth forecasts

Effect on the Stuies: The Council staff's approach will tend to favor delay.

AFUDC ON SUNK COSTS

Difference: The council includes the additional AFUDC due to delay on the IOU share of WNP-3 sunk costs as a cost of delay. BPA does not because the added present value of AFUDC on sunk costs is purely an artifact of the difference between the 3 perent real discount rate used in SAM and the higher real AFUDC rate, and because some IOU's may be able to include portions of the sunk costs in the rate base before commercial operation. BPA did conduct a sensitivity analysis and discovered that inclusion of AFUDC does not significantly change results.

Effect on the Stuies: Inclusion of AFUDC on sunk costs favors earlier restart and increases total project cost somewhat.

INTEREST RATES

Difference: The Council assumes a 3 percent real interest rate on the net-billed share of WNP plants, while BPA assumes a 13 percent nominal rate; which equates to a 6.6 percent real rate.

Effect on the Studies: The Council assumption improves the cost effectiveness of WNP-3 only to a limited extent, since the 3 percent interest rate was also applied to alternative resources.

LIFECYCLE vs. PERPETUAL REPLACEMENT PRESENT VALUE

Difference: The Council staff compute the costs of various scenarios over the lifecycle of each resource added during the 20-year planning horizon. They have also computed present values assuming perpetual replacement of all resources, using a range of replacement revenue costs. To date, the Council has not chosen between the lifecycle or perpetual replacement approaches. BPA staff use only the perpetual replacement approach, believing that the lifecycle approach neglects important end effects.

Effect on the Studies: The lifecycle approach tends to favor early restart over delay.

Differences Between the Current WNP-3 Restart Study and the May 26 Report

Differences in Data, Assumptions, and Methods:

The May 26 Report used the January 1983 load forecast which was a little higher than the July 1983 load forecast being used in the WNP-3 restart studies. However, the July 1983 forecast is actually slightly (roughly 100 average MW) higher than the forecast used for the May 26 report, in the years that are most critical to the choice of restart date, i.e. the late 1980's and early 1990's. Hence, the new forecast had little impact on the economics of restart.

In the May 26 report, the Investor Owned Utilities (IOU) 30 percent share of the capital cost of completing WNP-3 was calculated assuming identical financing assumptions as were used to calculate BPA's 70 percent share. This method somewhat understated the IOU share in present value terms. For the restart study, BPA used the Financial Model (FIN) associated with the System Analysis Model (SAM) to more accurately calculate the IOU's share. This change increases the present value of the cost to complete WNP-3.

SAM is constantly being improved to more accurately model the regional power system. Since the completion of the May 26 report, several changes have been made to SAM. No before-and-after runs have been made to assess the significance of these SAM changes, but they are not believed to have significantly influenced the economic analysis results.

The Supply System has now estimated costs for slower-paced construction schedules that are lower than costs for the more rapid schedules. Given a slow construction pace, the Supply System estimates now show a relatively small construction cost penalty for delay.

A 13 percent interest rate is now assumed for bond sales for the net-billed share of WNP-3, based on DRI forecasts and advice from Wertheim. The May 26 report assumed bonds would be issued at a 13-percent rate through June 1983 and 12 percent thereafter.

Differences in Results:

The new results are generally consistent with the May 26 results, when straight-across comparisons are made, but the new results are somewhat more favorable towards delay. The May 26 results and the new results are compared below.

May 26 Report

Alternative	On-line Dates WNP-3	On-line Dates WNP-1	Financing	Construction Pace	System Cost Increase Over 1a
1a	12/86	6/91	Conventional	Fast	--
2a	12/89	6/93	Conventional	Fast	$+105 MM
2a/2g Hybrid	12/89	6/91	Conventional	Fast	$+213 MM

New WNP-3 Restart Analysis

Alternative	On-line Dates WNP-3	On-line Dates WNP-1	Financing	Construction Pace	System Cost Increase Over 1a	System Cost Increase Over F-1
A-1	12/87	6/91	Conventional	Fast	--	--
C-1	12/89	6/91	Conventional	Fast	$+ 98 MM	--
C-1a	12/89	6/93	Conventional	Fast	$- 27 MM	--
F-1	6/88	6/91	Conventional	Slow	--	--
D-3	6/90	6/91	Conventional	Slow	--	-87

The May 26 report indicated that a 3-year delay of WNP-3 accompanied by a further 2-year delay in WNP-1 (alternative 2a), would increase system costs by $105 million. The new results indicate a decrease of $27 million for the same alternative ([illegible]a), as compared to the earliest possible on-line date for WNP-3 (12/87 in alternative A-1).

BPA also analyzed a 3-year delay of WNP-3 with no delay of WNP-1 in both reports. Alternative 2g was the WNP-3-only delay alternative in the May 26 report. However, 2g was not directly comparable to the no-delay alternative (1a), because partial revenue financing was assumed for 2g and not for 1a. Assuming conventional financing for WNP-3 in alternative 2g (2a/2g Hybrid) makes it comparable to 1a, and shows a $213 million penalty for the delay.

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The corresponding alternative in the new analysis is C-1, which has a $9[illegible] million penalty.

In the new study, construction restart dates with slower construction pace were also evaluated. These comparisons showed a smaller construction cost penalty due to delay given a slow construction pace. For this reason, the FY 83 comparison indicates that delay is more economic than immediate restart, by $87 million. Such a comparison of slow construction paces was not made in the May 26 study. Both the May 26 report and current studies indicate that significant economic penalties begin to accrue for delays of greater than 4 years, assuming the base load forecast.

In summary, the overall study result has changed from slightly favoring earliest completion, to showing no clear advantage for either immediate restart or delay. This result should not be surprising, since WNP-3 construction has already been ramped-down to a significant extent.

Supply System Nuclear Power Plant Costs

Estimates of WNP-3 costs to complete were submitted to BPA by the Supply System in an August 10, 1983, document (updated September 23) which summarizes six construction cash flows for four restart alternatives and two termination cashflows. WNP-1 5-year delay cashflow to complete was submitted to BPA August 26, 1983, and is shown in table 7.

Three alternative means of financing WNP-3 were evaluated: a bank loan at 12.5 percent for 12 years, BPA revenues, and a combination of BPA revenues (for preservation costs) and conventional bond financing at 13 percent ove 35 years.

The 30 percent IOU share of WNP-3 costs were assumed to be financed with a 10.2 percent interest rate on debt-financing, a [illegible].4 percent return on equity and a 12.1 percent AFUDC rate. The financial submodel (FIN) of the System Analysis Model (SAM) was used to estimate the annual capital revenue requirements on the IOU share.

The annual payments required to pay off IOU costs and net-billed costs wer discounted to 1982 to find the present value of capital costs using a 6 percent inflation rate and 3 percent real discount rate. The present value of the direct payments from BPA revenues was found simply by discounting revenue-financed costs back to 1982.

The table below shows the unescalated and undiscounted sum of construction cash flows in 1983 dollars, the sum of construction cash flows in inflated and escalated but undiscounted nominal dollars, and the present value of the capital costs streams to amortize the direct construction costs recovered from ratepayers over the projects' lives.

Direct Construction Costs, To Complete

(Millions of dollars)

	WNP-3					WNP -1
	A1	B2	C1	F1	D3	
Sum of Construction Cash Flows, 83$	1460	1632	1682	1434	1590	1856 (82$)
Sum of Cash Flows, Nominal $'s	1686	2025	2196	1737	2193	2864
Present Value						
BPA 70%	1304	1442	1430	1303	1386	
IOU 30%	909	1012	1038	911	989	
Total PV	2213	2454	2468	2214	2375	2323

Table 6 shows the detailed cash flows, in 1983 dollars, for these five scenarios. Scenario D3 and F1 involve January 1984 and July 1985 restart dates, respectively, and are characterized by a slow, more economic, construction pace. Table 6 also shows cash flow with no delay. Table 7 shows WNP-1 cash flows.

Table 8 shows the Supply System's new estimate of remaining costs and salvage value, should WNP-3 be terminated.

Table 6
WNP-3
CASH FLOW SUMMARY
(100% Ownership Amounts, $ in Millions)

Scenario Period	BASE CASE No Delay Base 1983 Dollars	CASE 1 A Base 1983 Dollars	CASE 2 B Base 1983 Dollars	CASE 3 C Base 1983 Dollars	CASE 4 D Base 1983 Dollars	CASE 6 F Base 1983 Dollars
1983 3rd	$ 107	$ 63	$ 63	$ 63	$ 63	$ 63
4th	130	50	50	50	50	50
1984 1st	130	69	36	36	36	42
2nd	124	88	27	27	27	48
3rd	122	100	17	17	17	50
4th	118	105	36	15	15	45
1985 1st	104	113	53	9	9	76
2nd	93	115	63	10	10	93
3rd	87	110	84	16	16	103
4th	81	107	97	36	36	106
1986 1st	64	103	144	53	53	109
2nd	55	93	143	63	63	109
3rd	35	86	141	84	63	103
4th	16	81	138	97	63	93
1987 1st	5	64	103	144	63	86
2nd	3	54	93	143	62	81
3rd	-	35	86	141	62	64
4th	-	16	81	138	61	54
1988 1st	-	5	64	103	59	35
2nd	-	3	54	93	57	16
3rd	-	-	35	86	77	5
4th	-	-	16	81	93	3
1989 1st	-	-	5	64	100	-
2nd	-	-	3	54	99	-
3rd	-	-	-	35	86	-
4th	-	-	-12	16	73	-
1990 1st	-	-	-	5	64	-
2nd	-	-	-	3	54	-
3rd	-	-	-	-	35	-
4th	-	-	-	-	16	-
1991 1st	-	-	-	-	5	-
2nd	-	-	-	-	3	-
TOTAL	$1,274	$1,460	$1,632	$1,682	$1,590	$1,434

Table 7
WNP-1
CASH FLOW SUMMARY
5-YEAR DELAY - CASE 1B
($ In Millions)

	Base June 1982 Dollars	Escalation	Total With Escalation
Actual Thru June 1982	1,708.7	$ -	$1,708.7
July 1982	$25.1	$0.2	$25.3
August 1982	13.5	0.2	13.7
September 1982	3.8	0.3	4.1
October 1982	26.7	0.8	27.5
November 1982	8.5	0.4	8.9
December 1982	22.7	1.2	23.9
January 1983	7.1	0.4	7.5
February 1983	8.9	0.4	9.3
March 1983	6.3	0.5	6.8
April 1983	5.4	0.3	5.7
May 1983	5.0	0.4	5.4
June 1983	4.9	0.5	5.4
July 1983	(10.5)	0.5	(10.0)
August 1983	3.6	0.6	4.2
September 1983	(10.7	0.5	(10.2)
October 1983	10.5	1.5	12.0
November 1983	4.3	0.6	4.9
December 1983	4.4	0.5	4.9
1984			
1st Quarter	16.9	1.7	18.6
2nd Quarter	15.7	1.8	17.5
3rd Quarter	12.7	3.6	16.3
4th Quarter	22.4	5.1	27.5
1985			
1st Quarter	24.3	4.9	29.2
2nd Quarter	34.9	7.0	41.9
3rd Quarter	39.7	12.4	52.1
4th Quarter	57.4	18.3	75.7
1986			
1st Quarter	70.0	23.3	93.3
2nd Quarter	81.2	26.9	108.1
3rd Quarter	85.2	39.5	124.7
4th Quarter	98.9	43.9	142.8

(TABLE 7 Continued)
WNP-1
CASH FLOW SUMMARY
5-YEAR DELAY - CASE 1B
($ In Millions)
Page 2

	Base June 1982 Dollars	Escalation	Total With Escalation
1987			
1st Quarter	95.1	45.6	10.7
2nd Quarter	95.0	45.7	10.7
3rd Quarter	93.4	49.4	12.8
4th Quarter	92.5	49.3	11.8
1988			
1st Quarter	92.8	50.0	12.8
2nd Quarter	80.5	50.1	30.6
3rd Quarter	74.3	53.8	28.1
4th Quarter	72.9	50.6	23.5
1989			
1st Quarter	64.3	49.4	13.7
2nd Quarter	59.1	44.2	03.3
3rd Quarter	57.5	49.2	06.7
4th Quarter	53.1	46.9	00.0
1990			
1st Quarter	46.1	41.1	7.2
2nd Quarter	53.1	49.1	02.2
3rd Quarter	43.8	45.7	9.5
4th Quarter	32.2	33.5	5.7
1991			
1st Quarter	27.0	28.9	5.9
2nd Quarter	23.5	25.4	8.9
3rd Quarter	1.3	1.2	2.5
Total to GO	$1,856.3	$1,007.3	$2.63.6
Total at Completion	$3,565.0	$1,007.3	$4.72.3

Note: Escalation was calculated from a June 1982 base at 9 percent compounded annually.

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Table 8
WNP Termination Case 7
Decision made July 85
(millions 83$)

Salvage receipts (July 85 to July 87) $70

Site Restoration Costs (July 85 to July 87) $20

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
CASE 7
NUCLEAR PROJECT NO. 3
CASH FLOW SUMMARY*
(100% Ownership Amounts, $ in Millions)

Calendar Years	Productive Work	Delay Costs	Total 1983 $
1983			
3rd Quarter	$35	$28	$63
4th Quarter	25	25	50
1984			
1st Quarter	13	23	36
2nd Quarter	10	17	27
3rd Quarter	-	17	17
4th Quarter	-	15	15
1985			
1st Quarter	-	9	9
2nd Quarter	-	10	10
3rd Quarter	-	2	2
4th Quarter	-	3	3
1986			
1st Quarter	-	6	6
2nd Quarter	-	9	9
3rd Quarter	-	4	4
4th Quarter	-	2	2
1987			
1st Quarter	-	2	2
2nd Quarter	-	2	2
TOTAL	$83	$174	$257

*This cash flow summary excludes anticipated salvage value and site restoration, which is assumed to be relatively straightlined from July 1985 to July 1987.

Net Present Value of Cost of Termination Case 7 is $181.

II FINANCIAL IMPLICATIONS

BPA's Financial Status

The following table compares BPA's estimated operating results for FY 1983 as contained in its 1983 final rate proposal with projected FY 1983 requirements from the 1982 final rates. Rather than paying amortization and deferral to the Treasury as had been planned in the 1982 rate case, BPA now estimates that it will have to defer an additional $83.4 million at the end of FY 1983.

FY 1983 Estimated Program Costs
and Revenue Forecast

($ in millions)

	1982 Final Rates	1983 Final Rates Submittal
A. Fixed Costs		
INTEREST/APC		
- Corps/Bureau O&M	72.3	71.0
- Bureau Interest	20.6	20.5
- BPA Bond Interest	126.2	129.9
- Off-Budget Interest	2.0	0.0
- Appropriations Corps/BPA	174.0	169.5
Subtotal	395.7	390.9
RESOURCE PLANNING & ACQUISITION		
- Exchange	667.7	623.1
- Net-Billed Plants	673.9 2/	708.6
Subtotal	1,341.6	1,331.7
TOTAL FIXED COSTS	1,737.3	1,722.6

	1982 Final Rates	1983 Final Rates Submittal
B. Operating Expenses		
RESOURCE PLANNING & ACQUISITION		
- Dir. Acquisitions	48.9	34.8
- Use of Facilities	25.2	23.8
- Res. Plng./Oversight & Program Costs	16.0	15.4
Subtotal	90.1	74.0
ENERGY CONSERVATION	3.6	4.0
SYSTEM PLANNING & CONSTRUCTION		
- EPRI	7.7	7.3
- R&D	5.5	5.5
Subtotal	13.2	12.8
SYSTEM OPERATION	--	28.3
SYSTEM MAINTENANCE	92.3 3/	62.4
POWER MARKETING	16.8 4/	11.1
POWER SCHEDULING	--	3.4
FISH & WILDLIFE	10.4	9.8
EXECUTIVE MANAGEMENT	0.0	0.0
REGIONAL COUNCIL	5.7	6.1
MS&A	0.0	0.0
TOTAL OPERATING EXPENSES	235.2	211.9
PROGRAM COST TOTAL	1,972.5	1,934.5
C. Payments to Treasury & Cash Lag		
Amortization	6.2	0.0
Deferral	217.9	(83.4)
Subtotal	224.1	(83.4)
Cash Lag	30.0	33.0
REVENUES APPLIED	2,226.6	1,884.1

1/ Includes increased intrest costs associated with the higher estimated FY 1983 borrowings.

2/ Includes Hanford of $.. million.

3/ System Operations anc maintenance Combined.

4/ Power Marketing and Sceduling Combined.

CASH FLOW FORECAST
BASE FY 1984

9/12/83

($ in millions)	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Beginning Cash Balance	$84												$ 84
Receipts from operations	93	66	69	124	81	82	150	112	123	143	76	76	1,195
Trust	6	6	6	6	6	6	6	6	6	6	6	6	72
Borrowing/(repayment)		40										250	290
Total Receipts	99	112	75	130	87	88	156	118	129	149	82	332	1,557
Outlays													
O & M, Reg. Council, &	18	18	20	19	19	22	21	22	21	21	22	20	243
Construction	15	17	12	11	12	13	12	12	13	17	17	17	168
Conservation	8	8	9	9	10	10	10	11	11	11	12	12	121
Residential Exchange	14	12	15	17	14	12	10	10	8	9	10	13	144
Pur. Power & Wheeling	47	38	26	12	1	1	1	1	1	8	6	33	175
Int. on Current Bonds	7	2	9	6		49	7	5	9	6		49	149
Trust	6	6	6	6	6	6	6	6	6	6	6	6	72
Total Outlays	115	101	97	80	62	113	67	67	69	78	73	150	1,072
Net Cash Balance	68	79	57	107	132	107	196	247	307	378	387	569	569

September 30 Transactions

Less: Corps & Bureau O & M	(86)
Interest on Corps, Bureau & BPA appropriated debt & on the deferral	(198)
Ending cash balance	(85)
Available for payment on the deferral	$ 200

Assumptions:

A revenue forecast of $2.764 billion from rates (7-25-83) was used for this forecast.

Outlays are based on the figures shown in the Supplemental Rate Case.

Receipts and purchased power are adjusted for net-billed energy costs of $902 million. IOU Residential Exchange revenue of $771 is taken out of receipts and netted against costs. Only the net outlays for both are shown above.

LArmstrong (WP-DT-0354F-pg. 7)

CASH FLOW FORECAST
1984 WNP-3 Construction Financed Through Revenues

9/12/83

($ in millions)	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Beginning Cash Balance	$84												$ 84
Receipts from operations	93	66	69	124	81	82	150	112	115	143	76	76	1,187
Trust	6	6	6	6	6	6	6	6	6	6	6	6	72
Borrowing/(repayment)		40										250	290
Total Receipts	99	112	75	130	87	88	156	118	121	149	82	332	1,549
Outlays													
O & M, Reg. Council, &	18	18	20	19	19	22	21	22	21	21	22	20	243
Construction	15	17	12	11	12	13	12	12	13	17	17	17	168
Conservation	8	8	9	9	10	10	10	11	11	11	12	12	121
Residential Exchange	14	12	15	17	14	12	10	10	8	9	10	13	144
Pur. Power & Wheeling	47	38	26	20	7	6	15	14	26	19	31	46	295
Int. on Current Bonds	7	2	9	6		49	7	5	9	6		49	149
Trust	6	6	6	6	6	6	6	6	6	6	6	6	72
Total Outlays	115	101	97	88	68	118	81	80	94	89	98	163	1,192
Net Cash Balance	68	79	57	99	118	88	163	201	228	288	272	441	441

September 30 Transactions

Less: Corps & Bureau O & M	(86)
Interest on Corps, Bureau & BPA appropriated debt & on the deferral	(198)
Ending cash balance	(85)
Available for payment on the deferral	$ 72

Assumptions:

The assumptions for this are identical to the base case of the same date.

The only difference lies in an increase of $125.6 million in WNP-3 fund requirements to fund construction from revenues beginning in Jan. 84.

LArmstrong (WP-DT-0354F-pg. 8)

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CASH FLOW FORECAST
BASE FY 1985

9/12/83

($ in millions)	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
[illegible]	[illegible]												
[illegible]	110	[illegible]	[illegible]	120	91	92	177	118	153	150	79	78	1,326
Trust	7	7	7	7	7	7	7	7	7	7	7	7	84
Borrowing/(repayment)												255	255
Total Receipts	117	87	85	127	98	99	184	125	160	157	86	340	1,665
Outlays													
O & M, Reg. Council, &	20	20	21	21	21	24	21	24	22	22	25	21	262
Construction	12	14	10	9	10	11	10	10	11	14	13	13	137
Conservation	8	8	9	9	10	10	10	11	11	11	12	12	121
Residential Exchange	13	15	19	21	19	18	15	15	13	12	14	15	189
Pur. Power & Wheeling	35	24	8	3	2	2	2	2	2	10	4	4	98
Int. on Current Bonds	7	5	9	6		63	7	5	9	6		63	180
Trust	7	7	7	7	7	7	7	7	7	7	7	7	84
Total Outlays	102	93	83	76	69	135	72	74	75	82	75	135	1,071
Net Cash Balance	100	94	96	147	176	140	252	303	388	463	474	679	679

September 30 Transactions

Less: Corps & Bureau O & M	(89)
Interest on Corps, Bureau & BPA appropriated debt & on the deferral	(202)
Ending cash balance	(85)
Available for payment on the deferral	$ 303

Assumptions:

A revenue forecast of $3.028 billion from rates (7-25-83) was used for this forecast.

Outlays are based on the figures shown in the Supplemental Rate Case.

Receipts and purchased power are adjusted for net-billed energy costs of $753 million. IOU Residential Exchange revenue of $898 is taken out of receipts and netted against costs. Only the net outlays for both are shown above.

LArmstrong (WP-DT-0354F-pg. 9)

CASH FLOW FORECAST
1985 WNP-3 Construction Financed Through Revenues

9/12/83

($ in millions)	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Beginning Cash Balance	$85												$ 85
Receipts from operations	110	80	78	120	91	92	162	94	132	150	79	78	1,266
Trust	7	7	7	7	7	7	7	7	7	7	7	7	84
Borrowing/(repayment)	50											205	255
Total Receipts	167	87	85	127	98	99	169	101	139	157	86	290	1,605
Outlays													
O & M, Reg. Council, &	20	20	21	21	21	24	21	24	22	22	25	21	262
Construction	12	14	10	9	10	11	10	10	11	14	13	13	137
Conservation	8	8	9	9	10	10	10	11	11	11	12	12	121
Residential Exchange	13	15	19	21	19	18	15	15	13	12	14	15	189
Pur. Power & Wheeling	56	46	33	27	18	17	23	20	10	26	38	37	351
Int. on Current Bonds	7	5	9	6		63	7	5	9	6		63	180
Trust	7	7	7	7	7	7	7	7	7	7	7	7	84
Total Outlays	123	115	108	100	85	150	93	92	83	98	109	168	1,324
Net Cash Balance	129	101	78	105	118	67	143	152	208	267	244	366	366

September 30 Transactions

Less: Corps & Bureau O & M	(89)
Interest on Corps, Bureau & BPA appropriated debt & on the deferral	(202)
Ending cash balance	(85)
Available for payment on the deferral	$ (10)

Assumptions:

The assumptions for this are identical to the base case of the same date.

The only difference lies in an increase of $316.7 million in WNP-3 fund requirements to fund construction from revenues.

LArmstrong (WP-DT-0354F-pg. 10)

In its 1983 rate proposal, BPA has established a revenue requirement which is sufficient to cover all projected costs through June 30, 1985, including: (1) payment of debt service on outstanding WNP-1, WNP-2, and WNP-3 bonds; (2) completion of construction and subsequent operation of WNP-2; and (3) 70 percent of ramp-down/preservation costs for WNP-3. Should the Supply System be required to resume construction on WNP-3, even though such construction currently cannot be financed by the Supply System, 70 percent of the cost of such construction would have to be funded from BPA revenues. An increase in WNP-3 related costs will likely exceed BPA's revenue requirements during the rate period by at least $360 million more than BPA included in its current rate proposal if construction were resumed in January 1984.

If BPA were ordered to pay WNP-3 construction costs from its revenues, its deferral of Treasury payments, already a sensitive financial and political issue, would be increased. If construction of WNP-3 is restarted on January 1, 1984, and if BPA is unable to raise rates to cover the increased revenue requirement, BPA would be unable to make planned amortization payments and payments on the deferral of $441 million during FY 1984 and FY 1985. Higher deferrals would result if construction began before January 1, 1984.

The attached BPA cash flow forecasts compare costs included in the 1983 rate proposal for FY's 1984 and 1985 with costs which would occur in those years if construction on WNP-3 were to resume.

III RATE AND LOAD IMPACTS

The rate impacts of the WNP-3 restart alternatives were projected for the priority firm rate through fiscal year (FY) 2000. The industrial firm power rate will show no variation in the short-term and a pattern of variation similar to the priority firm rate in the long term. This is a result of the interpretation used for this analysis of the post-1985 rate directives contained in the Regional Act. The industrial firm power rate is linked to the priority firm rate after 1985. However, the rate can be no lower than the rate in effect during operating year 1985. This "floor rate" is what prevents any variation in the industrial power rate in the short term.

The results illustrate the effects of alternative construction restart dates, construction paces, funding arrangements, and termination scenarios. The effects of alternative load forecasts were not examined at this time due to the complexity of determining revenue over- or underrecovery during the 1984-85 rate period as a result of loads that differ significantly from those used to develop the rates for that period.

For this analysis, it was assumed that the rates in effect for the 1984-85 rate period were fixed. If a change in the status of WNP-3 resulted in an absolute increase of Supply System costs, then the difference was assumed to be recovered through rates in effect during FY 1986.

The results presented below were based on assumptions, costs, and decisions from BPA's 1983 wholesale power rate filing. Existing resource capability, current and outyear budget information, and information on surplus power marketing efforts and resource operation were all used in the development of these results. Alternative payment schedules on net-billed Supply System projects, new resource schedules, and Supply System project on-line dates were developed specifically for this analysis.

Alternative Restart Dates

RATE IMPACTS
(Constant 198[illegible] mills/kWh)
Priority Firm Rate

FY	A1	B2	C1
1985	[illegible]	22.6	22.6
1986	[illegible]	22.1	21.8
1987	[illegible]	23.1	22.8
1990	[illegible]	24.2	24.2
1995	[illegible]	21.1	21.3
2000	[illegible]	22.5	21.7

This comparison indicates the effect on rates of restarting WNP-3 in January 1984 (A1), July 1984 (B2), or July 1985 (C1). There is a rate benefit in FY 1986 to delaying construction. However, earlier construction leads to lower rates in all other years for priority firm customers if long-term financing of such costs were available. This is largely due to earlier inclusion of WNP-3 output in the Federal Base system (FBS) and a lower cost for new resources which impacts the average system cost of exchanging utilities.

Alternative Financing Rates

RATE IMPACTS
(Constant 198[illegible] Mills/kWh)
Priority Firm Rate

FY	A2	C2
1985	22.[illegible]	22.6
1986	23.[illegible]	22.1
1987	23.[illegible]	23.0
1990	24.[illegible]	24.8
1995	21.[illegible]	21.6
2000	21.[illegible]	22.0

Alternatives A2 and C2 correspond to alternatives A1 and C1, respectively, except that they assume a 15 percent finanacing rate on funds to complete WNP-3 and WNP-1 instead of 13 percent. In both cases, the power rates are higher in each year due to the higher cost of borrowing.

Revenue Funding

RATE IMPACTS
(Constant 1985 Mills/kWh)
Priority Firm Rate

FY	C6	D1	C1
1985	22.6	22.6	22.6
1986	23.8	23.5	21.8
1987	26.8	24.1	22.8
1990	23.2	23.7	24.2
1995	20.4	20.8	21.3
2000	21.1	21.6	21.7

The regional or system economics of funding large baseload projects out of current revenue cannot be separated from the impacts that this action will have on wholesale rates. Alternatives C6 and D1 indicate the impacts of funding the net-billed share of WNP-3 construction out of current BPA revenues beginning July 1985 at a full construction pace (C6) and a partial construction pace (D1). Full construction pace implies manpower peaks of approximately 4000 people and less efficient manpower utilization than the partial construction pace. Revenue funding is assumed in scenarios C6 and D1. The C1 forecasts, based on conventional bond financing, are provided for comparison.

The rate impacts of the revenue financing cases are the most severe in the short term of all the other alternatives. Funding from current revenues provides a trade-off between the short and long-term ratepayer benefits. Rates are high during the construction period and then are significantly lower after that, as a result of the absence of debt-service in the revenue financing cases.

Bank Financing

RATE IMPACTS
(Constant 1985 Mills/kWh)
Priority Firm Rate

FY	A1	A6	B1
1985	22.6	22.6	22.6
1986	22.7	21.8	21.6
1987	22.8	22.7	22.7
1990	23.8	24.2	24.8
1995	20.8	21.1	21.6
1996	20.7	21.6	24.1
2000	21.4	21.0	21.8

Alternatives A6 and B1 assume that construction is funded through bank financing. The rate impacts are not significantly different from conventional financing except that bank financing requires a balloon payment on part of the funds borrowed 12 years from the initial borrowing, which is assumed to b paid out of revenues. This occurs in FY 1996 for both alternatives A6 an B1. Alternative A1 is provided to indicate the impacts in FY 1996 of th ballon payment in that year.

Longer Restart Delays

RATE IMPACTS
(Constant 1985 Mills/kWh)
Priority Firm Rate

FY	C1a	D2
1985	22.6	22.6
1986	21.0	20.4
1987	21.7	20.6
1990	23.9	22.0
1995	21.8	25.1
2000	22.0	22.1

Alternative C1a is similar to alternative C1 in that it assumes a restart date for WNP-3 construction of July 1985. However, alternative C1a assumes that construction on WNP-1 is also delayed an additional 2 years to June 199 Alternative D2 assumes a 5-year delay in WNP-3 and an additional 4-year delay in WNP-1. These alternatives indicate that there are short-term rate benefits relative to 1, 2, and 3-year delays in WNP-3, with WNP-1 on its current schedule. However, rates become higher in the longer term due to construction activity and the higher costs of new resources. This is especially evident in alternative D2 with the longer delay in WNP-1

Termination Before Restart

RATE IMPACTS
(Constant 1985 Mills/kWh)
Priority Firm Rate

FY	T1	T2	T7
1985	22.6	22.6	22.6
1986	20.7	20.0	21.8
1987	21.1	19.7	21.6
1990	22.1	20.4	22.0
1995	23.8	25.5	23.7
2000	23.5	26.3	23.0

Alternatives T1, T2, and T7 examine the possibility of controlled termination of WNP-1 in 1985, with WNP-3 also being terminated at the same time in alternative T2. The restart dates for WNP-3 differ between alternatives T7 (January 1984) and T1 (July 1985). The results indicate that there are rate benefits through FY 1990 for all termination cases relative to the delay alternatives. Rates then become significantly higher through FY 2000.

These results are perhaps the most sensitive to changes in forecasted loads. Higher loads would significantly increase the rate impacts of a termination. High-cost new resources would be required to meet any higher level of loads. By the same token, lower loads could mitigate the longer term rate impacts shown in these results. Finally, the costs of new resources and conservation assumed for this analysis that would replace the terminated Supply System project(s) play a major role in determining the rate impacts.

Termination After Restart

RATE IMPACTS
(Constant 1985 Mills/kWh)
Priority Firm Rate

FY	T1	T2	T7
1985	22.6	22.6	22.6
1986	21.8	21.8	22.6
1987	22.7	22.7	23.0
1990	23.4	22.7	23.2
1995	24.8	27.2	24.5
2000	24.2	27.6	23.7

These alternatives assume that construction on WNP-3 and WNP-1 is resumed AND then termination occurs on one (T1 and T7) or both (T2) plants in late 1988. Due to the increased amount of debt as a result of additional construction, the rates are higher than those under the controlled termination alternatives. The short-term rate reductions indicated in the controlled termination alternatives are virtually eliminated in these alternatives and the longer term rate impacts are even greater. The same qualifications on the results apply as for the controlled termination alternatives.

Effect of Revenue and Bank Financing of Loads and Cost Recovery

The revenue and bank financing options for restarting construction on WNP-3 entail heavy front-end loading of the recovery of Supply System costs through rates. Consequently, these financing options will increase near-term retail electricity prices. Prices under these options are expected to be higher in the near term compared with BPA's latest (July 1983) baseline load forecast, but lower in the 1990's.

A critical question is whether this near-term boost in rates might depress loads to the point where BPA cannot recover its fixed revenue requirements. BPA's electricity demand models were exercised to address this question. The results suggest that the revenue and bank-financing options can be expected to reduce loads in the near term by anywhere from 50 to 150 average MW (somewhat less than 1 percent of total regional firm loads). In the long term, the lower prices in the 1990's will counteract that early reaction to the point that loads in the year 2000 may be higher than the BPA base case by about the same amount. With regard to the DSI's, there is no anticipated impact on loads if the current aluminum ingot price projections are realized, but it should be cautioned that the Northwest aluminum industry will be subject to more cyclical swings if electricity prices increase in the near term.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

ROBERT W. BONNER, Q.C.
CHAIRMAN

970 BURRARD STREET
VANCOUVER, B. C.
V6Z 1Y3

21 October 1983

Mr. Daniel Meek, Counsel
Subcommittee on Mining, Forest
Management and the Bonneville
Power Administration
1626 Longworth Building
Washington, D. C.
20515

Dear Mr. Meek:

Thank you for your letter of 14 October advising us of the hearing on 27-28 October on Northwest power issues. We have decided not to take part in the hearing next week.

In my letter of 5 July 1983 I discussed our expected power surpluses during the next few years. We estimate B. C. Hydro will have a firm hydroelectric energy surplus until the early 1990's. As previously discussed, without a change in planning criteria it is unlikely that firm energy surpluses will exist beyond that date, but about 4000 GW.h of interruptible hydroelectric energy under average streamflow conditions could be available for sale to the Pacific Northwest and California.

B. C. Hydro is presently investigating various methods for marketing its surplus energy, including provision of special rates to industrial customers to encourage increased production at existing plants. We are also keeping informed on the progress of BPA and Northwest utilities in marketing surplus firm power to California to determine the potential for B. C. Hydro to participate in this market.

With regard to limitations BPA might impose on access to the Pacific intertie, we have discussed such issues with BPA. Since we expect to have both firm and interruptible surpluses for the next few years we would be concerned about any access policy that would unduly restrict open competition for the California market.

We appreciate being kept informed of your Subcommittee's activity and regret that we will not be able to attend your hearing in Washington, D. C. next week.

Yours very truly,

Robert W. Bonner

COMMENTS OF
THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

The Public Utilities Commission ("CPUC") is the agency of the State of California charged with responsibility for reviewing the reasonableness of actions taken by privately-owned utilities providing retail electrical service in California and, based on the results of such review, for setting the rates to be charged for such service. In its efforts to carry out this responsibility, the CPUC has participated in the last several proceedings conducted by the Bonneville Power Administration ("BPA") to establish rates for wholesale electrical power and in the various proceedings undertaken by the Federal Energy Regulatory Commission ("FERC" or "Commission") and the courts to review the rates established by the BPA. Based on the experience gained through this participation, the CPUC submits the following comments.

A. BACKGROUND

1. Applicable Statutes Require that the BPA Base its Rates for the Sale and Transmission of Electrical Power on the Cost of Providing Service to Each Class of Customers.

Section 7 of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Act), 16 U.S.C. §839, sets forth the standards to be followed by the BPA in establishing rates for the sale and transmission of electrical power. Section 7(a)(1) of this act directs the BPA to establish rates in accordance with the Flood Control Act of 1944 (Flood Control Act), 16 U.S.C. §825, and the Federal Columbia River Transmission System Act (Transmission System Act), 16 U.S.C. §838. Section 7(a)(2) provides that such rates shall become effective only if found by the FERC to be sufficient for the BPA to meet its financial obligations and recover its total costs. Section 7(i) directs the BPA to give proper notice; conduct hearings, including the presentation of evidence and the cross-examination of witnesses; develop a full and complete record; and, based on the record thus developed, provide a full and complete justification of the rates established.

Section 7(k) provides special direction concerning rates established by the BPA for the sale of nonfirm energy within the United States but outside the Pacific Northwest. Under this Section, the FERC is directed to review these rates for conformance with the requirements of the Flood Control Act, the Transmission System Act, and the Bonneville Project Act, 16 U.S.C. §832. Such review is to be based on the record developed by the BPA. As part of that review, parties to the proceedings conducted by the BPA are to be afforded an opportunity for an additional hearing to be conducted in accordance with the procedures established by the FERC pursuant to the Federal Power Act.

As interpreted by the FERC, applicable statutes require more than a mere showing proposed rates would be sufficient to recover the BPA's total costs. U.S. Secretary of Energy, Bonneville Power Administration, "Order Remanding Rates Without Prejudice," issued in Docket No. EF80-2011 on November 21, 1980, mimeo at 11-12. Rather, to insure that such rates are consistent with statutory standards, the BPA is required to explain how revenues and costs are allocated among its various classes of customers --

and thus how rates are designed. Id. at 12. In this regard, any rate charged a class of customers not based on the cost of providing it service must be affirmatively justified. Id. at 12-13. In the words of the FERC, "The Commission has to affirm that the various components of the BPA's overall pricing scheme meet the tests set forth in [applicable statutes]. Specifically, the Commission must address whether the rate scheme encourages the widest use of BPA power and provides the lowest rates to consumers consistent with sound business principles." Id.

Certainly, therefore, the BPA has discretion regarding the design of its rates. But just as certainly, the exercise of such discretion is not unbridled. Rather, the BPA is required to demonstrate that rates charged each class of customers are based to the maximum extent practicable on the costs of providing it service. As the BPA stated in a notice issued on November 30, 1979, concerning its adoption of various standards established by the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §260 et seq.,

> Rates charged by Bonneville for providing electric service to each class of its customers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class. The costs of providing electric service to each class of electric customers shall, to the maximum extent practicable, be determined on the basis of reasonable, accepted accounting methods. Such methods shall to the extent practicable permit identification of differences in cost-incurrence, for each such class of electric customers, attributable to daily and reasonable time of use of service and permit identification of differences in cost-incurrence attributable to differences in customer demand, and energy components of

> cost. In prescribing such methods, Bonneville will use embedded and long-run incremental costs. The rate design will always consider such an embedded cost-of-service analysis but will also consider other facts, such as marginal or long-run incremental cost principles, the purposes of equity, and the need to meet legal considerations.

44 Fed. Reg. 68948.

2. Practical Considerations Dictate that the BPA Base its Rates for the Sale and Transmission of Nonfirm Energy and Surplus Power on the Marginal Costs of Providing Such Services.

In general, as repeatedly recognized by the BPA, resources are used most efficiently when goods and services are priced at their marginal cost of production. See, for example, page 2 of Exhibit No. BPA-6 presented during the "1983 Proposed Wholesale Power and Transmission Rate Adjustment Proceeding." Obviously enough, given a fixed amount of productive resources, the decision to produce more of a particular good or service has the effect of reducing production of other goods and services. To reflect this effect, and thus to encourage efficient use of resources, the price charged for any good or service should reflect the cost of producing one more or less unit: its marginal cost.

More specifically, as frequently asserted by the CPUC, marginal costs provide an appropriate basis for setting rates to be charged for wholesale electric power. On this basis, efficiency can be promoted since the least costly combination of resources insures against overuse (which would occur if price is set below marginal cost) and under-use (which would occur if price is set above marginal cost). As a result, by avoiding wasteful use, conservation of resources can be encouraged. Similarly, equity can be insured since no customer over- or under-pays relative to the cost of a particular resource. In other words, customers purchasing less power save the cost of resources not used and those purchasing more pay the cost of resources actually used. At the same time, financial obligations can be met since variations in cost resulting from variations in output are automatically reflected in rates and thus in revenues.

Recovery of total costs on this basis necessitates a proper allocation of fixed and variable costs among the various classes of customers. In turn, such an allocation requires recognition that the BPA installs capacity, and thus incurs fixed costs, for the sole purpose of serving firm load in the Pacific Northwest. Accordingly, the BPA should seek to recover its fixed costs only from those customers receiving firm service -- that is, from those for whom capacity is installed.

On the other hand, costs associated with the production of nonfirm energy and surplus power are wholly variable. They arise only from the operation of existing facilities, and in no way relate to the need for new. Logically, therefore, rates charged customers purchasing nonfirm energy or surplus power should not reflect fixed costs, but only variable operating costs -- unless in the future the BPA should actually install resources for the purpose of generating nonfirm energy and surplus power.

Similarly, costs associated with deferral, industrial reserves, the Washington Public Power Supply System (WPPSS), the residential exchange, and new resources should not be reflected in rates charged for nonfirm energy and surplus power. None of these costs relates in any way to the provision of these services. In the first place, having for several years now paid rates substantially in excess of the costs of providing them service, purchasers of nonfirm energy cannot be said to have contributed to the BPA's need to defer payments to the U.S. Treasury. Similarly, given the BPA's refusal to interrupt service to its industrial customers to provide nonfirm service, the costs saved by the availability of industrial reserves cannot logically be charged to nonfirm customers. In the case of the WPPSS, construction was undertaken for the sole purpose of serving firm load in the Pacific Northwest. In the same vein, since it is intended only to make more uniform the rates charged residential customers in the Pacific Northwest, the residential exchange serves to produce no power whatsoever. All the more questionable in light of the BPA's projection of unsold surplus is any idea that new resources are acquired to provide surplus power. In fact, if any doubt exists as to why surplus may go unsold, one need merely realize that the BPA has set the rates for surplus power too high.

Notwithstanding the foregoing discussion, some adjustment to rates based strictly on marginal cost may in certain circumstances be appropriate. As a practical matter, since the operation of surplus resources is optional, the BPA could decide not to offer nonfirm energy and surplus power for sale at rates based strictly on marginal costs. In this light, nonfirm energy and surplus power may be seen to take on the character of incremental energy:

that is, power which the BPA has the option to produce or not produce. The establishment of some premium may be necessary, therefore, to provide the BPA with sufficient incentive to operate surplus resources.

Any such premium should not be set so high, however, as to create too strong a reliance for the BPA on sales of nonfirm energy and surplus power nor as to require customers receiving such service to bear an unreasonably large share of fixed costs. In the first place, because sales of nonfirm energy are highly volatile due to changing conditions of supply and demand, an excessive premium would create the strong likelihood that the BPA would under-recover its total costs and thus fail to meet its financial obligations. Furthermore, insofar as purchasers of nonfirm energy and surplus power would be required to pay rates in excess of the cost of providing them service, the result would be highly inequitable. Moreover, by serving to reduce rates charged in the Pacific Northwest, an excessive premium would encourage the consumption of firm energy, and thus the wasteful use of resources.

3. Despite Protections Afforded Under Present Law, Certain Statutory Changes Are Needed to Insure Fair, Nondiscriminatory Treatment for the BPA's Customers Located Outside of the Pacific Northwest.

As discussed previously, existing law affords important protections to the BPA's customers. Thus, in establishing rates, the BPA is required to develop a full and complete record. In addition, based on the record thus developed, it is required to provide a full and complete justification of rates established.

Furthermore, such rates are subject to review by the FERC to determine their conformance with statutory requirements -- in particular, that they be based to the maximum extent practicable on the cost of providing service to each class of customers. Most importantly, as part of that review, parties to the proceedings conducted by the BPA are afforded an opportunity for an additional hearing.

Despite these protections, however, the BPA's customers located outside of the Pacific Northwest face a significant threat of unfair, discriminatory treatment. In the first place, the procedures followed by the BPA provide for no separation of its staff who participate during the formal proceedings and those who advise the Administrator. As a result, the BPA's staff enjoys an opportunity denied all other parties to influence decisionmaking off the record. Under such circumstances, serious doubt will always exist as to whether the BPA's rates are in fact based on the record formally developed. In addition, as another instance in which the threat of discriminatory treatment arises, the BPA's staff during the hearings recently held and its Administrator in his record of decision refused to provide any clear indication as to how exactly nonfirm energy and surplus power would be offered for sale. Thus, although specific rates were proposed, virtually unlimited discretion was reserved regarding the terms and availability of these services.

At the same time, the FERC's review of the BPA's proposed rates creates distinct possibilities for unfair, discriminatory treatment. In the first place, the FERC has declined to include in the hearings it conducts rates proposed by the BPA for the sale of surplus power. Consequently, compliance by the BPA with the requirements of applicable statutes as they apply to such sales cannot be determined. In addition, the FERC has expressed its belief that its role is but appellate in nature, thus declining to substitute proper rates for deficient ones proposed by the BPA. As a result, strong potential exists for substantial delay as one set of rates after another is first rejected by the FERC and then resubmitted by the BPA.

To insure fair, nondiscriminatory treatment for the BPA's customers located outside of the Pacific Northwest, therefore, certain statutory changes are needed. First, for the record developed by the BPA to be accorded any weight, a separation should be imposed between the BPA's staff who participate at hearings and those who advise the Administrator. Second, for proposed rates to gain any sense of fairness, the BPA's discretion regarding the sale of nonfirm energy and surplus power should be closely restricted. Third, for their review to prove meaningful, rates proposed for the sale of surplus power should be included in the hearings conducted by the FERC. Finally, for review to be expedited and delay avoided, the FERC should be expressly authorized to fix rates to be charged by the BPA for the sale of nonfirm energy and surplus power.

B. ANSWERS TO QUESTIONS FOR CALIFORNIA UTILITIES AND AGENCIES

Q.1 BPA's final studies for the 1983 rate proposal show that BPA expects revenue from surplus firm power sales to increase from $28 million in FY 1983 to $186 million in Operating Year (OY) 1985. Is this a reasonable projection of the additional revenue BPA can expect to obtain from surplus firm power sales to California?

A.1 No. Neither the load forecast nor the rates is reasonable.

The initial rate proposal forecasted OY 85 surplus firm power and energy sales of 333 average megawatts (aMW). This forecast is based on a combination of FY 1983 experience and judgment regarding the progress of current negotiations (Exhibit BPA-15, pages 6 to 8). However, experience continues to be that less surplus firm sales are made than are forecast. Further, there is no current evidence that California utilities will need the electricity or buy it on a discretionary basis at the proposed rates. Nor is there information that current negotiations are progressing toward more sales, or that parties are expressing interest which will sum to the forecast level of sales. The final rate proposal forecast of 684 aMW (an increase of 351 aMW over the initial forecast) does not reflect experience or reasonable judgment.

The sales and revenue forecast are problematic because the surplus firm power and energy proposed rates are not based on BPA's costs. Furthermore, the rates for surplus firm power actually are a range having neither floor nor ceiling when applied via the thermal, exchange and purchased power rates. The unknown level of the rates, the unbridled potential for rate discrimination (e.g., different rates at the same time for the same power to different customers), BPA's failure to include the option to substitute nonfirm for surplus firm in the surplus firm rate schedules (an option included in current surplus firm sales and one which encourages surplus firm sales), and the uncertainties inherent in BPA's administration of the rates all serve to prevent reasonable forecasts of BPA surplus firm revenues.

Q.2 BPA's final rate studies also show that BPA anticipates revenue from nonfirm surplus energy sales to California to increase from $150 million in FY 1983 to $201 million in OY 1985, even though BPA expects nonfirm surplus energy sales to California to decline from 1932 average megawatts (aMW) in FY 1983 to 1635 aMW in OY 1985. This implies a nonfirm surplus energy rate increase to California of 58%--BPA expects 34% more revenue from 15% lower sales. Is this a reasonable projection of the additional revenue BPA can expect to obtain from nonfirm surplus energy sales to California?

A.2 No. The proposed rates and rate administration are unreasonable, and prevent reasonable projections of revenues.

BPA's final nonfirm rate proposal provides for controversial new rates (e.g., displacement) and new rate administration (e.g., spill rate implementation based on revenue needs, not operating characteristics; displacement rate sales concurrent with other sales). It allows BPA such a wide range of options that little can be said with much certainty. The final proposal is, however, clearly not based on BPA's costs of providing nonfirm service and requires undue discrimination in rate administration. The range of rates and the uncertainties in their implementation make unreasonable BPA's revenue forecast in its final rate proposal.

BPA unfortunately appears to have selected the course of maximizing its revenue from nonfirm sales. This course produces rates above the cost BPA incurs to provide the service. It results in devices to unfairly discriminate between customers (e.g., displacement rate to reduce BPA's competition in the nonfirm market; probable inequities in the operation of the guarantee when offered to "preferred" customers and not to others). It results in rate administration with revenue maximization as the operating rule (e.g., spill rate implementation) rather than BPA's own ratemaking standards of equity, efficiency and cost basis for the rates. This path produces rates which are unfair, inequitable, not cost based, which will produce economic inefficiencies, and which creates confusion, suspicion and distrust. It will require pursuing the full length of appeals available to the affected parties. Rates and rate administration based on BPA's costs to provide nonfirm service will result in rates substantially below those in BPA's final rate proposal. BPA's revenue forecasts within this context are not reasonable.

Q.3 Overall, BPA expects to collect $387 million from the California utilities in OY 1985, if it is assumed that the California utilities are the market for BPA's surplus firm power sales. This compares to total BPA revenue from California of about $178 million during FY 1983 (excluding firm capacity purchases) and appears to be an increase of about 117%. Can BPA realistically expect to recover this much additional revenue from the California utilties?

A.3 No. BPA's final proposed rates are discriminatory, unfair, excessive and unreasonable. The load forecasts for both surplus firm and nonfirm are uncertain within this context. An increase in the forecasted demand for surplus firm power is not reasonable given the final proposed rates and uncertainties in rate administration. Uncertain load forecasts, unreasonable rates, an ambiguous range of rates for surplus firm power and unclear rate administration do not combine to validate BPA's revenue projections.

Q.4 What control over BPA's budget and expenditures is available to BPA's customers?

A.4 BPA's customers do not have any direct control over BPA's budget and expenditures. Customers indirectly affect BPA's costs by changes in their purchases from BPA. As purchases by customers (BPA sales) change, so will BPA costs, budgets and expenditures. This effect points out the need for rates to be based on BPA's marginal costs. As purchases by customers (BPA sales) change, changing BPA costs, budgets and expenditures, revenues will not match costs unless rates are based on marginal costs.

Q.5 What suggestions do the California utilities have for improving BPA's repayment performance?

A.5 BPA can improve its repayment performance by basing its rates on its cost of service.

Rates must reflect the costs incurred to provide the service. The Pacific Northwest (PNW) has not installed and is not now installing any capacity to serve out-of-region firm loads. PNW capacity is installed to serve PNW firm load. BPA's repayment performance can be dramatically improved by recognizing this one simple fact.

Since BPA's capacity costs are incurred to meet PNW firm loads, BPA's regional customers should pay the costs incurred to meet their needs. Repayment shortages result when capacity costs are charged out-of-region customers and out-of-region sales are less than forecast. Those repayment shortages occur because of BPA's attempt to shift PNW costs out of the region.

Furthermore, repayment shortages both in and out of the PNW in large part occur because actual sales fall short of projected sales, upon which revenues to recover the revenue requirement are based. Forecast sales, however, cannot be expected to equal actual sales. The problem is not better forecasts but better ratemaking. Rates must ensure stable "earnings" (repayments to the U.S. Treasury) given uncertainty. The solution is to base rates on BPA's marginal costs. When rates are based on BPA's marginal costs, as sales vary, revenues will vary concurrently with BPA's variation in costs, resulting in stabilized "earnings" (repayments to the U.S. Treasury).

BPA's marginal costs for out-of-region sales do not include capacity costs. If necessary to give BPA an incentive to provide the service, in some circumstances rates may include a premium. The premium included in out-of-region rates, however, must be fair and reasonable. BPA's recent surplus firm and nonfirm rates, and 1983 final proposed surplus firm and nonfirm rates, include an unfair and excessive premium above BPA's costs. BPA's dependence on potentially volatile sales, the rates for which contain a large premium above BPA's cost of service, magnifies BPA's risk of not meeting its repayment obligations. This excessive premium substantially contributes to BPA financial instability.

However reasonable or unreasonable, BPA forecasts it will collect $395 million, or 13.2%, of its total operating year 1985 wholesale power revenue requirement from sales to California under its proposed rates and rate administration. This is a significant portion of BPA's total revenues and will have a significant effect on BPA's repayment performance. BPA's proposed rates and rate practices, however, will exacerbate BPA's repayment problems rather than provide the cure. Rates based on BPA's marginal costs of service (with out-of-region marginal cost based rates correctly exclusive of capacity costs even if inclusive of a reasonable incentive premium) will more nearly solve BPA's repayments problems.

Q.6 What is the position of the California utilities on H.R. 3177, the proposed BPA Fair Ratemaking Act of 1983?

A.6 We have no comments at this time, except to note that proposed paragraph 7 seems to make the rates in the hearing officer's initial decision (or those modified by the Administrator within 60 days) BPA's final rates. This appears to preclude FERC review. Such procedural reform would be untenable. Review by FERC is essential, to enable and ensure an independent agency without its own self-interest at stake to arbitrate complex conflicts. We are continuing to examine other aspects of this bill.

Q.7 Would the California utilities favor a proposal requiring BPA to submit rate adjustments to FERC for confirmation and approval 6 months prior the proposed effective date if FERC were (1) required to complete its review (both under Regional Act Section 7(a)(2) and Section 7(k)), based on the record in BPA's proceeding, within the 6 month period, and (2) empowered to order all BPA rates increased by a uniform percentage to cover any perceived prospective revenue shortfalls?

A.7 No. First, FERC should base its decisions on its own record, not the record developed in the BPA proceeding since only an FERC hearing can assure the independent fact gathering separate from an agency which (perhaps correctly so) must be devoted to its own self interest. Second, an external restriction on the time limit for review is undesirable unless FERC is given more resources to adequately meet this burden.

Timely review by FERC is clearly desirable, but not at the expense of fair and equitable review. Third, it is of paramount importance that BPA's rates be based on costs (for financial stability to BPA, as well as equity, efficiency and conservation). A uniform percentage rate increase is unlikely to reflect the costs of providing service except by coincidence.

The unique relationship between the BPA and FERC in establishing rates under Section 7(k) of the Pacific Northwest Electric Power Planning and Conservation Act, however, merits some special procedures to avoid duplication of effort and provide an early determination by FERC. It might be feasible to establish a joint hearing procedure for that portion of the proceeding which covers rates which are to be finally established by FERC. Certainly the BPA proceeding should include evidence covering all FERC requirements needed for the determination of the final rates. If the joint hearing procedures are deemed feasible, it might include preparation of the initial decision on the 7(k) issues by the FERC hearing officer, with the BPA Administrator and other parties having the opportunity to comment within thirty days of the publication of the initial decision.

Q.8 How much nonfirm surplus energy did BPA sell to the California utilities during August 1983? September 1983? October 1983? Were the California utilities during any of these months willing to pay BPA's present NF-2 standard rate (18.2 mills/kWh) for this energy? Did BPA offer such NF-2 standard rate energy to the California utilities during each of these months?

A.8 This information is more directly available from the utilities.

Q.9 What are the California utilities' present plans for expanding transmission capacity between the Northwest and California? Have these plans progressed since the Subcommittee's hearing on transmission in Eugene, Oregon, on July 11, 1983? Do the California utilities agree with the recommendation of the U.S. General Accounting Office that, if no agreements for substantial intertie expansion have been reached within 1 year, the Secretary of Energy should direct BPA and WAPA to seek congressional approval to develop the most cost-effective intertie additions?

A.9 This information is more directly available from the utilities.

Q.10 What policies should BPA adopt to determine which Northwest utilities shall have access to the Pacific Intertie for making power sales to California?

A.10 BPA should provide access to the Pacific Intertie utilizing policy principles and objectives which are consistent with BPA's regional transmission policies. Intertie capacity should be made available as needed to effectuate transactions specified in agreements entered into between buying and selling parties for the contracted amount of electricity. Intertie access should not be predetermined, but should be the natural result of buyers and sellers agreeing to transactions. Requests for access in excess of Intertie capacity (with access based on actual agreements for sales) will not occur since buyers on the southern portion of the Intertie cannot obligate themselves beyond the capacity of the Intertie. Northern Intertie allocation is now made on this basis, and this policy merits continuation.

BPA has convened a proceeding to consider this question. The CPUC's response to the BPA's request for recommendations is attached.

C. CONCLUSION

Based on the foregoing discussion, the CPUC recommends that the following statutory changes be enacted:

1. that a separation be imposed between the BPA's staff who participate at hearings and those who advise the Administrator;
2. that the BPA's discretion regarding the sale of nonfirm energy and surplus power be closely restricted;
3. that rates proposed for the sale of surplus power be included in the hearings conducted by the FERC; and
4. that the FERC be expressly authorized to fix rates to be charged by the BPA for the sale of nonfirm energy and surplus power.

ADDRESS ALL COMMUNICATIONS
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Public Utilities Commission
STATE OF CALIFORNIA

FILE NO

October 14, 1983

Ms. Donna L. Geiger
Public Involvement Manager
Bonneville Power Administration
P.O. Box 12999
Portland, Oregon 97212

Dear Ms. Geiger:

The California Public Utilities Commission (CPUC) submits the following comments and recommendations in response to the Bonneville Power Administration's (BPA) request for recommendations on the development of a Pacific Northwest - Pacific Southwest Intertie Access Policy. As expressed in BPA's Notice (file No. TIE-1), the need to develop an Intertie Access Policy results from requests by non-federal parties seeking contractual access, on both a firm and non-firm basis, to capacity on the Northwest portion of the Intertie.

The BPA recently published a proposed transmission policy (May 25, 1983, File No. TrP-1) which covers planning for the region's transmission resources and use of the BPA transmission system for non-federal power. Several transmission policy principles and objectives are developed therein which may equally apply to the Intertie Access Policy:

1. "to integrate and transmit power from existing or additional federal or non-federal plants";
2. "to provide interregional transmission opportunities";
3. to be "compatible with ... the environment and fish and wildlife";
4. "to achieve as nearly as practicable the maximum efficiency, reliability, economy and other benefits, as if the region's system were owned by a single utility";
5. to provide "access to available (intertie) capacity ... for all utilities on a fair and non-discriminatory basis";
6. to provide "federal wheeling ... under terms which will encourage use of the federal system so that the benefits of interconnection and of system diversity will be realized by

the region's electric power consumers to the greatest extent possible"; and

7. that "BPA wheeling contracts are intended to be an agreement to provide service to a customer, but not to grant the right to resell to third parties the use of the capacity of BPA facilities."

Further, BPA's proposed transmission policy provides "an integration service for the firm wheeling of firm and nonfirm power up to contractual limits..." Firm wheeling is proposed to be provided on BPA facilities "as specified in the agreement between the parties for the contracted amount of transmission demand." This approach to wheeling over BPA's network facilities may be applied in a similar manner to the Northwest portion of the Intertie.

Intertie capacity should be made available as needed to effectuate transactions as specified in agreements entered into between buying and selling parties for the contracted amount of electricity. Intertie access should not be predetermined, but should be the natural result of buyers and sellers agreeing to transactions. Requests for access in excess of Intertie capacity will not occur since buyers have restricted access on the southern portion of the Intertie and therefore cannot obligate themselves beyond the capacity of the Intertie. Northern Intertie allocation is now made on this basis, and this policy merits continuation.

Intertie access allocation which is the natural result of agreements to transactions meets all seven principles and objectives. First, electricity will be integrated and transmitted from existing and additional federal and non-federal plants since this policy will allow all present and future federal and non-federal plants the opportunity for Intertie access when sales agreements are reached which require the Intertie to integrate supplies with demands. Second, it will provide for interregional transmission access since all parties will have the opportunity for unrestricted participation. Third, it is compatible with the environment and fish and wildlife concerns since sellers will not agree to a sale which violates Pacific Northwest environmental, fish and wildlife laws and regulations. Furthermore, economic transactions which are compatible with the environment (e.g., using hydro rather than coal) will naturally result when access is not restricted and buyers seek the least cost alternatives.

Fourth, it will maximize efficiency, reliability, economy and other benefits as if the region's transmission system is owned by one utility. Allocation of capacity to subsets of the whole before agreements for transactions are made would not occur on a system owned by one utility. A single utility would dispatch its system only as transactions are made, and then in order of least cost first. Efficiency, reliability and economy are maximized if capacity is allocated once transactions are finalized since this gives all parties the opportunity to seek the most desirable transactions without uneconomic restrictions (i.e., maximize efficiency), seek the quality of transactions (e.g., firm, nonfirm, length of time) that most meets the region's supply and the buyer's needs (i.e., maximize reliability), and at the least cost to the buyer and the most revenue to the seller (i.e., maximize economy). Also, buyers will buy in order of least cost first, sellers will dispatch resources in order of least cost first, maximizing the economy of the transactions and other benefits (e.g., reduced pollution when pollution costs are internalized as part of economic dispatch). BPA notes in its draft transmission policy that the similar policy on the regional network "provides the greatest general efficiency for both BPA and a wheeling customer..." This is also true when this policy is applied to Intertie access allocation.

Fifth, access will be fair and non-discriminatory since all utilities will have the opportunity without restriction to seek and secure a transaction. Sixth, this policy will encourage use of the Intertie by providing the opportunity for the most participation in fair, non-discriminatory, economic transactions; it will realize the benefits of interconnection and system diversity by allowing all utilities which are interconnected to exploit system diversity to the fullest economic extent; and it will provide benefits realized to the region's consumers to the greatest extent possible by allowing the region's utilities to obtain and distribute the most benefits as can be secured through transactions. Seventh, this policy will allow BPA to provide service to a customer and will avoid the need for resales, consistent with BPA's intent.

By contrast, a policy which predetermines access independent of actual transactions between buyers and sellers will periodically create unused capacity, failing to integrate power from existing or additional federal or non-federal plants, and failing to provide all interegional transmission opportunities. This will occur when sellers with Intertie capacity fail to find a buyer and make sales while other sellers fail to make sales not due to the lack of a buyer but due to the lack of Intertie access. Predetermined shares may cause pollution from coal plants operated by a utility with access while a hydro resource is unused by another utility without access, or fail to fully use energy created by the fish flow requirements, thus being incompatible with the environment and fish and wildlife concerns. Predetermined access independent of an agreement for transactions between a buyer and seller is not consistent with the operation of a resource by a single utility since a single utility would not separate portions of its system for one "user," but would mix users and resources as conditions develop to maximize efficiency and minimize cost.

Predetermined access will reduce the number of potential transactions since the number of sellers will be controlled by their access, thus inhibiting efficiency and reliability. It will not provide for the least cost purchases nor the least cost dispatch of resources as a result of the restriction on the quality and quantity of transactions, preventing economy and other benefits. Predetermined access must necessarily discriminate between potential sellers and cannot be fair to all parties. Neither use of the federal system, nor additional interconnection, nor full utilization of system diversity will be encouraged since Pacific Northwest utilities will not interconnect nor use their diversity beyond their share of the Intertie. In fact, utilities with insufficient access to the federal system will be encouraged to bypass it with

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their own interconnections, thus reducing use of the the federal system. Benefits will not be realized by the region's customers to the greatest extent possible with predetermined access since some customers will not receive benefits their utility would othewise obtain for them if their access is not limited. Finally, reselling of unused allocated Intertie capacity will be encouraged, either creating inequitable and inefficient economic rents or underutilized capacity, while violating BPA's policy not to grant resale rights.

Thus, the CPUC recommends that Intertie access principles and objectives be adopted which are consistent with BPA's transmission policy. Access to capacity on the Northwest portion of the Intertie should be allocated according to transactions between seller and buyer, consistent with both current practice and BPA's proposed network transmission policy. This approach will meet all principles and objectives and result in requests for access no more than Intertie capacity. Access should not be predetermined, but should be the natural result of actual transactions.

Sincerely,

Duncan Wyse

Duncan Wyse, Director
Policy & Planning Division

ANSWERS TO QUESTIONS POSED TO DIRECT SERVICE INDUSTRIES, INC. BY THE SUBCOMMITTEE ON MINING, FOREST MANAGEMENT AND BONNEVILLE POWER ADMINISTRATION

October 27, 1983

Q1 BPA's final studies for the 1983 rate proposal show an expected Operating Year (OY) 1985 DSI load on BPA of 2843 average MW (aMW), compared with a FY 1983 DSI load of 2072 aMW. This represents a 37% increase over a period of less than 2 years. These studies also show that BPA expects to collect 56% more revenue from the DSIs during OY 1985 ($656 million) than during FY 1983 ($420 million). Is 2843 aMW a reasonable projection of the OY 1985 DSI load on BPA? Is $656 million a reasonable projection of BPA's OY 1985 revenue from the DSIs?

A1 BPA's forecast of DSI loads during OY 1985 is reasonable if the present economic recovery and resulting demand for aluminum and other DSI products remains strong. If these economic conditions come to pass (which we all certainly hope), then it is reasonable for Bonneville to forecast $656 million of revenue from the DSIs during OY 1985.

One must recognize, however, that actual DSI loads and revenues could be above or below the forecast level, for at least two different reasons:

a. BPA has the right to restrict deliveries of power to the DSIs in order to protect its deliveries of firm power to other customers. It is not possible to forecast when or if such restrictions will occur. The usual reason for such occurrences are adverse water conditions or sudden failure of generating facilities, neither of which can be predicted in advance.

b. The present level of BPA power rates causes many of the DSI plants to be "swing plants" which can be economically operated only during strong economic conditions. This makes BPA load forecast subject to and dependent on forecasts of future economic activity in the U. S. and also in world markets. BPA's forecast that the DSI load during OY 1985 will be 2,843 avg. mw results from a simple arithmetic averaging of forecast DSI loads under strong and weak economic conditions.

Q2 Recent BPA reports show that, starting in 1987 and continuing thereafter, BPA expects the Industrial Firm rate to be lower than the Priority Firm rate. Would such a relationship between these two rates be consistent with the Regional Act or its legislative history?

A2 BPA projections of rates after 1985 consistently have shown that the DSI rate should be lower than the Priority Firm rate. This result is consistent with the Regional Act and BPA's cost of serving each customer group.

After July 1, 1985, the DSI rate essentially is set equal to the section 7(b) rate to preference agencies, plus a typical markup above wholesale resource costs to industries served by preference agencies, minus an adjustment for the lower cost of serving loads of the size and character of the DSI loads, and minus a credit for the value of the reserves provided by BPA's rights to restrict the DSIs. Properly applied, the downward adjustments for the lower cost of serving DSI loads should more than offset the "typical markup." The resulting DSI rate therefore should be at a level at or below the Priority Firm rate.

Q3 Should BPA interpret the Regional Act §7(b)(2) rate test and §7(c)(1)(B) rate methodology in a manner that could jeopardize the existence or value of the residential exchange for the exchanging utilities?

A3 The DSIs do not believe that there is a "cause and effect" relationship between the Section 7(b)(2) rate test, the Section 7(c)(1)(B) rate directive, and the "existence or value" of the Residential Exchange. The DSIs do believe that it is appropriate to consider whether the Residential Exchange can and should be maintained as a high-cost program under today's circumstances. When the Exchange program was proposed in the late 1970 and enacted by Congress in 1980, there was in fact a substantial lack of "parity" in the costs of power resources between public and private utilities in the Pacific Northwest. The intent of the Exchange program was to provide "parity" in the wholesale cost of resources. When the program was devised, no one could foresee that the problem of resource cost disparity would disappear in the normal course of events, but that has in fact happened as the region's publicly-owned utilities face increasingly higher costs. Moreover, as the Residential Exchange Program has been implemented, it has permitted the "exchange" and thus subsidation of a variety of non-resource costs, by both publicly-owned and privately-owned utilities, which has greatly increased the cost of the program to BPA and its ratepayers, particularly the DSIs.

After 1985, the costs of the Residential Exchange Program will be spread across all of BPA's ratepayers, in accordance with the statutory rate directives. All BPA customers should, therefore, support measures which will assure that the Residential Exchange Program exists to the extent necessary to achieve the original statutory purpose of parity in wholesale resource costs, but not as a major income transfer program.

The DSIs believe it would be entirely improper for BPA to attempt to manipulate any of the statutory provisions, particularly Sections 7(b)(2) or 7(c)(1)(B) solely to enhance the "existence or value" of the Residential Exchange Program. These statutory provisions must be administered in recognition of BPA's larger statutory obligation to market power throughout the region at the lowest possible cost and to recover sufficient revenues to recover all of its costs, including timely payments to the Treasury. BPA's rates to all customers, and particularly to the DSIs, must be established after 1985 at levels which reflect all of BPA's statutory obligations and which enable the DSIs to maintain their Northwest operations in the face of competitive realities elsewhere.

Q4 What control over BPA's budget and expenditures is available to BPA's customers?

A4 The DSIs believe that BPA's customers have substantial control over BPA's budget and expenditures, on several levels. Among the most important sources of control is the Congress, and particularly the regional delegation and interested committees through the budget review process. BPA's customers also have substantial opportunities to influence BPA's budget and expenditure process through formal proceedings and informal contacts with BPA itself, particularly in the rate hearing process. This 7(i) process necessarily involves careful scrutiny of the BPA revenue requirements for a rate period. BPA's formal policy development process and their practice of regularly consulting with customer groups on significant issues affords meaningful review of BPA's budget and expenditures.

Q5 What suggestions do the Direct Service Industries have for improving BPA's repayment performance?

A5 Peter Johnson has recently begun to improve BPA's repayment performance. The DSIs believe these actions are prudent and fiscally sound.

Bonneville's past underrecoveries were triggered by unusual and unlikely to be repeated circumstances, e.g., WPPSS cost overruns, poor load forecasts and an inability to have rates reflect increased costs in a timely manner. These problems have now been substantially resolved. Certainly WPPSS costs are under careful scrutiny. Load projections are unlikely to be affected by a combination of an unusually warm winter, California's limited energy demands due to record breaking hydroelectric generation, a particularly deep and long economic recession and its dramatic effect upon the aluminum market as well as all Pacific Northwest loads.

Perhaps the most important aspect of insuring BPA's repayment over the long-term is whether BPA's rates to the DSIs will be set at a level that will allow the Northwest aluminum industry to remain competitive and to continue to operate. BPA and the region can not afford to lose this revenue, especially during the current period of large power surpluses.

Q6 What is the position of the Direct Service Industries on H.R. 3177, the proposed BPA Fair Ratemaking Act of 1983?

A6 The position of the DSIs on HR 3177 is expressed in a letter dated August 8, 1983, addressed to Congressmen Swift and Wyden. A copy is attached for convenience.

Q7 Would the Direct Service Industries favor a proposal requiring BPA to submit rate adjustments to FERC for confirmation and approval 6 months prior to the proposed effective date, if FERC were (1) required to complete its review (both under Regional Act §7(a)(2) and §7(k)), based on the record in BPA's proceedings, within the 6-month period, and (2) empowered to order all BPA rates increased by a uniform percentage to cover any perceived prospective revenue shortfalls?

A7 The DSIs would strongly support a proposal which would require FERC to complete its review of BPA's rates within a six-month period from the date of filing. If the Ninth Circuit Court of Appeals affirms FERC's limited jurisdiction, as FERC has defined it, then a six-month period is adequate time for FERC to complete all of its review responsibilities. However, proposals which would allow FERC to unilaterally set or modify BPA's rate level or rate design, or force BPA into making a premature rate adjustment filing are not supportable.

As stated in the letter of August 8, referenced in question 6, the DSIs believe that the Administrator of BPA must be clearly and unequivocally accountable for BPA's rates and related policies. Neither a hearing officer nor FERC should have the authority to establish BPA rates, when the responsibility for managing the agency and achieving all of its statutory obligations necessarily rests with the BPA Administrator. Any statutorily required adjustment in the form of a uniform percentage increase would render BPA incapable weighing the myriad of factors necessary to ensure that their rates meet statutory standards.

Finally, the proposal to require a BPA rate filing with FERC 6 months before the planned effective date of the rates is ill advised. Such a requirement would result in a premature BPA filing which would be based upon projections and studies relying on data too far out of time with the rate period at issue. Further, due to the prolonged and contentious nature of the 7(i) process--the 1983 proceeding took about seven months--a 6-month filing requirement would exacerbate the "pancaking" problem of BPA rate filings at FERC.

Q8 Are the DSIs still purchasing energy from BPA under the 11.2 mills/kWh special rate offered since last spring? How much energy have the DSIs purchased under this special rate during each month? How much of this energy would the DSIs have purchased in any event at the standard Industrial Firm rate? Did the DSIs in any way decrease or replace their purchases of top quartile or firm quartile Industrial Firm power by buying the 11.2 mills/kWh energy?

A8 BPA's offer of nonfirm energy for startup of DSI curtailed plant operations covers the period March 21, 1983 through October 31, 1983. Between April 1 and the later part of July, 13½ aluminum potlines were restarted and the production of chemicals substantially increased. Total BPA load increased by about 775 megawatts. Net revenues to BPA over the period increased by over $25 million and about 1,600 people were brought back to work in the region. Obviously, the BPA nonfirm offer provided the desired results--a substantial increase in BPA revenues, largely from use of water that otherwise would have been spilled, and a notable improvement in the region's economy.

Specific information on monthly energy purchases under BPA's nonfirm sales to the DSIs is presently unavailable, but this information will be a matter of public record once BPA has computed all DSI bills for the period. The increase in load level as of July 31 (775 megawatts) indicates an order of magnitude that we hope will suffice for the Committee's purposes.

One could merely speculate how much, if any, of the significant increase in industry load and production would have occurred without BPA's offer of nonfirm energy. (BPA's offer was designed to avoid this problem by converting nonfirm power to Industrial Firm power at the regular rate if the price of aluminum improved.) Nevertheless, there is no question that the timing for and rate of recovery of Northwest aluminum and chemical industries' operations, and the attendant positive effects on the region's economy, were greatly speeded by the availability of this lower-cost energy. Further, it is apparent BPA's overall revenues were marketedly increased.

BPA's nonfirm offer did include provisions that enabled purchase of some power at the nonfirm rate that was being purchased at the industrial firm rate. This is matter currently under litigation and thus not a topic that can be discussed here. It should be noted, however, that the above mentioned $25 million increase in BPA revenues includes the effects of BPA's reduction in revenues resulting from this conversion. In sum, the entire region benefited from BPA's nonfirm sale.

DIRECT SERVICE INDUSTRIES, INC.
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Portland, Oregon 97232
(503) 233-4445

August 8, 1983

The Honorable Al Swift
1502 Longworth House Office Bldg.
Washington, D.C. 20515

The Honorable Ron Wyden
1406 Longworth House Office Bldg.
Washington, D.C. 20515

H.R. 3177--The BPA Fair Ratemaking Act

Dear Congressmen Swift and Wyden:

On behalf of BPA's direct service industrial customers (DSIs), I would like to thank you, your staffs and the staff of the Subcommittee on Energy Conservation and Power for the opportunity you have provided the DSIs and other interested parties to comment on H.R. 3177, The Bonneville Power Administration Fair Ratemaking Act of 1983.

As you know, the DSIs were essentially alone in formally opposing H.R. 3177 during the Subcommittee's general oversight hearing on June 13. At your request, we have since carefully reconsidered our position on the bill. The DSIs reluctantly have come to the conclusion that we still have serious concerns and we find we cannot support the proposed bill for the following reasons:

1. Consideration of Changes in BPA's Ratemaking Procedures is Premature Until We See Whether Existing Procedures Can Work.

BPA is just completing its third annual rate case under the Regional Power Act. Neither the Federal Energy Regulatory Commission nor the courts have completed their own review of BPA's first two rate cases. One of the major reasons BPA ratemaking is so contentious and uncertain is that no party knows what kind of review FERC and the courts ultimately will provide and what kind of record they must build in the proceeding below. Congress should wait to see how FERC and the courts interpret the existing rate directives and §7(i) procedures before adopting new procedures.

As a practical matter, BPA's implementation of the Regional Power Act and rate process are evolutionary. BPA initially was poorly equipped to deal effectively with either its vast new substantive responsibilities or procedural obligations under the Regional Act. Under the leadership of Peter Johnson, however, the agency now is in a position to handle its ratemaking and other tasks in a professional and business-like manner. Many of the complaints about BPA's initial rate proceedings under the Regional Act are now being resolved. Ongoing lawsuits will resolve others.

Perhaps more important, most of the major reforms contemplated by H.R. 3177 are already within BPA's existing authority under the Regional Act and prior legislation. Rather than enacting new procedures, Congress should exercise its oversight responsibilities to ensure that BPA's existing authorities are being carried out effectively.

2. Decisionmaking on BPA Rates Should Follow Responsibility for the Results of those Decisions.

The most significant change from existing law is that H.R. 3177 would establish a new independent hearing officer to make the initial decision on BPA rates. Although the Administrator would be allowed to change the hearing officer's decision based upon the record and with "a full and complete justification of the differences," as a practical matter, the fundamental ratemaking authority and responsibility would rest with the hearing officer, not the Administrator. Except in the case of the most obvious errors, the Administrator probably would be most reluctant to reverse the Hearing Officer. After all, if the rates developed by the Hearing Officer do not work, the Administrator simply could lament that rates are out of his or her control and shift responsibility to the Hearing Officer.

The principal reason the DSIs cannot support H.R. 3177 is that, as businessmen, we believe responsibility should follow accountability. H.R. 3177 would substitute the judgment of a part-time independent Hearing Officer for the judgment of the BPA Administrator who ultimately should be accountable to the region for establishing and carrying out BPA's policies. H.R. 3177 perhaps can be analogized to turning the steering wheel of a bus careening down a bumpy winding mountain road and loaded with the Northwest's power problems and consumers over to a newly licensed driver who can always walk away from any accident, while the more experienced BPA Administrator sits as a back seat driver responsible for cleaning up after accidents but subject to tremendous criticism if he or she grabs the steering wheel to change directions.

The issue is not whether a particular party to the BPA rate case can do better or worse if the decision is made by an independent Hearing Officer rather than by the BPA Administrator. The real issue is to establish a system where the person making a decision is accountable to the region for the results of that decision. We believe H.R. 3177 reduces accountability by dividing responsibility.

The need to keep the Administrator clearly accountable for BPA rates does not mean that the Hearing Officer should not have a broader role than Hearing Officers have had in prior BPA rate hearings. The Hearing Officer has heard months of evidence and read thousands of pages of testimony and studies. The Hearing Officer should use that knowledge and perspective to make recommendations to the Administrator and those recommendations should be carefully considered. But the Administrator must remain responsible for BPA's rates and the Hearing Officer's recommendations should not be binding in any way.

I have discussed with your staff my personal thoughts about how H.R. 3177 could be revised to strike a better balance between the roles of the Administrator and the Hearing Office. The attached amendment would empower the Hearing Officer to make recommendations on any element of the ratemaking process but leave responsibility to set rates with the BPA Administrator. Although the recommendations would be entitled to the deference due the Hearing Officer's position, the Administrator could reject the Hearing Officer's recommendations so long as there is substantial evidence in the rulemaking record considered as a whole to support the Administrator's decision. (This is the same standard as the standard for judicial review under §9(2)(2) of the Act.)

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3. More Process Doesn't Always Equate With Better Process.

Bonneville ratemaking is really the establishment of policy, not just the adjudication of ultimate facts. Congress wisely recognized this in §9(e)(2) of the Regional Power Act, which provides that "Nothing in this section shall be construed to require a[n adjudicative] hearing pursuant to section 554, 556 or 557 of the United States Code." Ratemaking is rulemaking. BPA's rate policies also must be integrated with its overall programs. An adjudicative type hearing is not the best way to make complex and interrelated policy decisions. By its nature, an adjudicative proceeding encourages parties to take extreme positions rather than working together to achieve reasonable compromises.

BPA's existing rate process already requires six to nine months of formal hearings. These hearings already tie up too many of the region's best utility executives, lawyers, economists and engineers for too long. We believe the region's time and effort could more productively be spent trying to solve the region's power problems rather than fighting over divisions of the existing power cost pie.

The requirements in H.R. 3177 to file proposed findings of fact and conclusions of law would lengthen and complicate the rate process. There is also a danger that the opportunity guaranteed by the bill to examine and refute any new evidence or studies could be misconstrued to allow an endless circle of examination even when the changes proposed by the Administrator at the end of the hearing are supported by substantial evidence on the record as a whole.

It should be noted that BPA's existing ratemaking procedures are already much more elaborate than the procedures of other Federal power marketing agencies, including the Tennessee Valley Authority. Outside of the Northwest, the trend appears to be against establishing cumbersome administrative litigation in favor of less formal legislative type hearings. Formal hearings tend to reduce the role of the general public and limit effective participation to the few parties who possess the legal and technical resources required by a formal process. (As drafted, H.R. 3177 could have this unintended result by prohibiting comments from the general public outside of the formal hearings. I have attached an amendment to the bill to preserve informal public comments.)

5. H.R. 3177 Will Not Reduce Court Appeals.

One of the laudable objectives of H.R. 3177 is to reduce judicial appeals and the resulting uncertainty over BPA rates by instilling more confidence in the BPA rate process. Unfortunately, the bill could have the opposite result. The stakes in BPA ratemaking are so great that no party can fail to appeal a decision it believes is wrong no matter how much process the party has had before BPA. Establishment of an independent Hearing Officer to make an initial decision and the requirement for findings of fact and conclusions of law encourage, not discourage, appeals to FERC and the courts by providing advocates additional arguments for review. Appeals can be reduced only if the parties are encouraged to work together to find reasonable compromises rather than being forced to take extreme positions in an adversarial process. Pacific Northwest power matters are simply too important to be left to lawyers and judges.

6. H.R. 3177 Would Open a Pandora's Box of Amendments to the Regional Power Act.

The Pacific Northwest faces a number of very serious electric power problems. All of the entities involved in regional power matters also are dissatisfied with aspects of the Regional Power Act. Consideration of H.R. 3177 could open a Pandora's box of amendments to the Regional Act. If the Act is to be reopened, it should be to deal with some of the substantive problems facing the region, in addition to any procedural problems that are not resolved by BPA, FERC or the courts in current proceedings.

Conclusion

The DSIs share your objective of trying to improve the BPA ratemaking process. But for the reasons explained above, we do not support H.R. 3177 at this time. The DSIs will continue to work with you and your staff on H.R. 3177 and the Northwest's pressing power and economic problems.

Very truly yours,

Brett Wilcox

Brett Wilcox
Executive Director

PROPOSED AMENDMENTS TO H.R. 3177

Insert, as a new paragraph the following new paragraph (3) and renumber the following paragraphs accordingly:

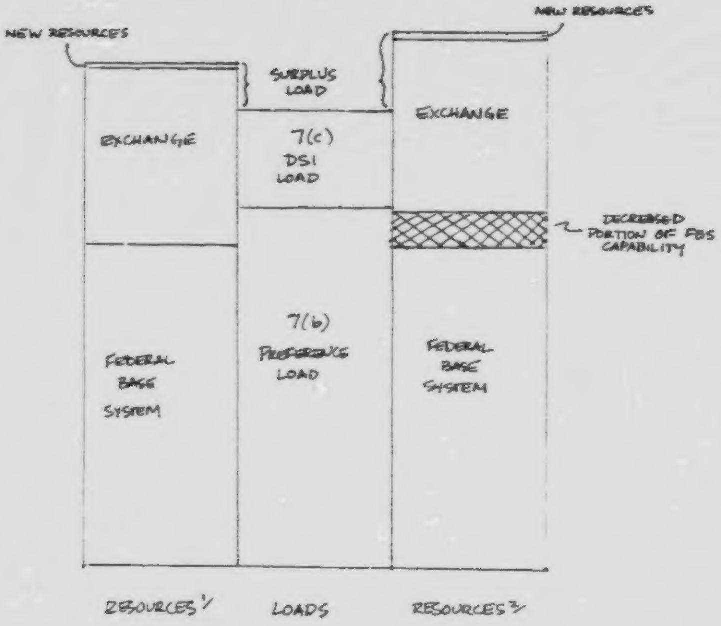
"(3) In addition to the opportunity to submit oral and written material at the hearings, any oral or written views, data, questions, and arguments submitted by persons not a party to the hearings prior to the close of the hearings shall be made a part of the administrative record."

Amend the existing paragraph (3) and delete paragraph (4) as indicated:

"~~(3)~~(4) After the record of the hearing has been closed, the hearing officer ~~shall-accord-interested-persons-who-have participated-in-the-hearing-a-reasonable-opportunity-to-file proposed-findings-of-fact-and-conclusions-of-law-respecting-the establishment-of-rates-pursuant-to-this-section;~~may make recommendations to the Administrator regarding any issues raised in the course of the hearings. The Administrator may reject a recommendation of the hearing officer provided that his decision is supported by substantial evidence in the rulemaking record required by this section considered as a whole.

Delete paragraph (7) and renumber remaining paragraphs.

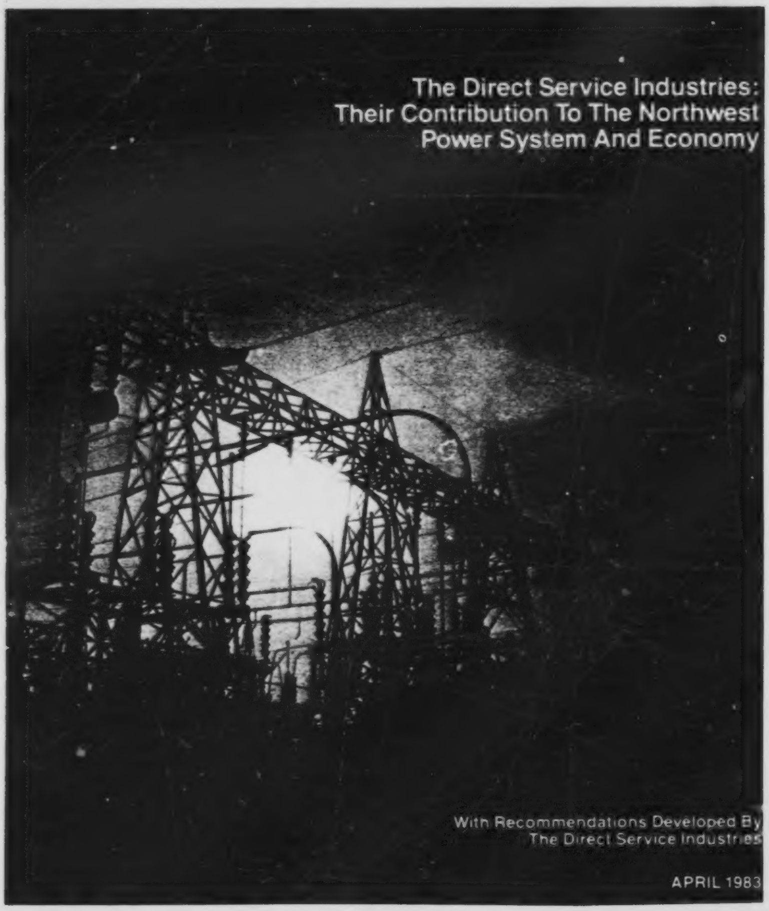
IMPACT ON PREFERENCE CUSTOMERS OF THE 1983 RATE CASE


NEW RESOURCES
NEW RESOURCES
SURPLUS LOAD
EXCHANGE
7(c) DSI LOAD
EXCHANGE
DECREASED PORTION OF FBS CAPABILITY
FEDERAL BASE SYSTEM
7(b) PREFERENCE LOAD
FEDERAL BASE SYSTEM
RESOURCES 1/
LOADS
RESOURCES 2/

1/ RESOURCES AS IDENTIFIED BY THE ADMINISTRATOR
2/ RESOURCES AS IDENTIFIED BY THE PUBLIC GENERATING UTILITIES

HIGHLIGHTS

Of A Study By Battelle Pacific Northwest Laboratories



The Direct Service Industries: Their Contribution To The Northwest Power System And Economy

With Recommendations Developed By
The Direct Service Industries

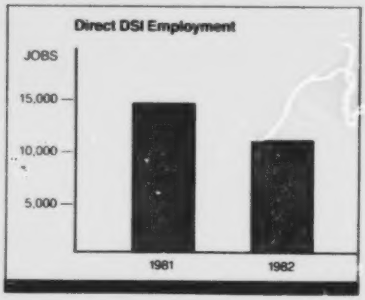
APRIL 1983

■ Highlighted below are findings of a study completed in April, 1983, for Direct Service Industries, Inc., by Battelle Pacific Northwest Laboratories, a research and development firm located at Richland, Washington. Also contained in this summary are recommendations developed by the direct service industries.

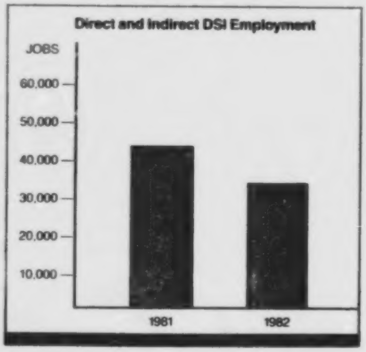
The study evaluates the contribution of the direct service industries (DSIs) to the Northwest power system and economy, and their competitiveness in major markets. The DSIs are 15 industrial firms with 20 plants in the Northwest that purchase electric power directly from Bonneville Power Administration to produce aluminum, metal alloys, chemicals, abrasives and forest products.

Economic Contributions to Northwest

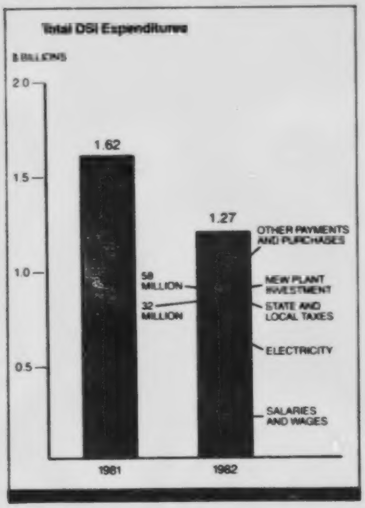
■ In 1981, DSI employment averaged 14,850 people, with support for indirect employment of about 29,700 jobs.



■ In 1982, due to higher power costs and worldwide recession, DSI employment fell to about 11,340 people, which indirectly created another 22,700 jobs.

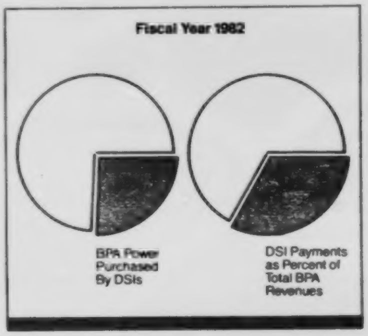


- The DSIs paid $450 million in salaries and wages in 1982. They also paid $379 million for electricity, $32 million in state and local taxes, and invested $59 million in plant improvements. These items, plus freight payments and purchases of materials, services and supplies, brought total DSI expenditures to approximately $1.27 billion, a $350 million decline from the 1981 level of $1.62 billion.



Power System Benefits

- In FY 1982, the DSIs purchased 26 percent of BPA's power but paid 34 percent of BPA's revenues.



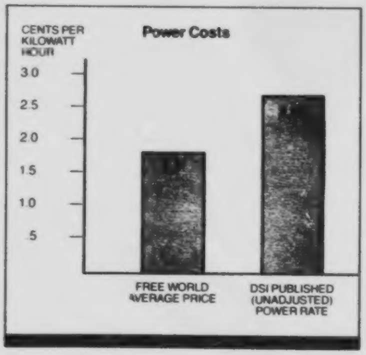
- Regionwide, over 2.1 million residential and small farm customers of Northwest utilities received over $216 million in electric rate relief during FY 1982. The DSIs pay most of the cost of this program. The average benefit amounted to about $100 per eligible household.
- BPA can interrupt DSI power supplies during emergencies or shortages. Battelle conservatively estimated that the annualized value of this reserve feature is over $163 million, which helps lower all BPA customer rates because costly standby power plants are not needed. The DSIs receive some credit for the reserves provided.
- DSI use of nonfirm energy for one-quarter of its power supply avoids the need to build additional power plants for this electricity load. It also provides BPA with a relatively assured market for as much as 900 megawatts of surplus power, which reduces the available surplus and lowers power costs to other BPA customers.

- High volume, constant DSI power loads reduce costs for all Northwest power consumers because BPA's system capacity is better utilized during nighttime and other off-peak hours.

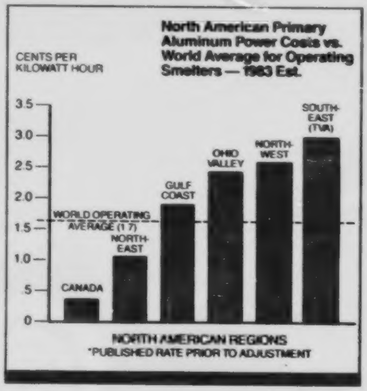
- Large, constant power purchases by DSIs help spread BPA's substantial fixed costs over a larger volume of kilowatt-hour sales, lowering costs for all power users.

Power Rates Determine Competitiveness

- Battelle estimates that 83 percent of the free world's operating aluminum smelters have lower power costs than the DSIs. The BPA's published (unadjusted) DSI power rate of 2.59 cents per kilowatt hour is about 50 percent higher than the present free world average price of about 1.7 cents per kilowatt hour for currently operating aluminum plants.

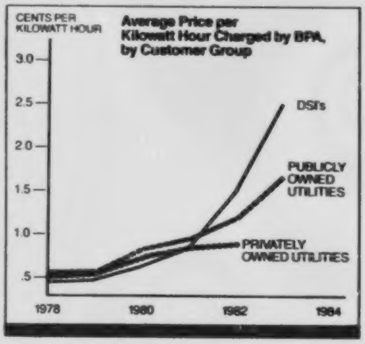

Power Costs

- The BPA published (unadjusted) power rate for its DSI customers is higher than any other aluminum producing region in North America except the Southeast's TVA system. Most aluminum plants that rely on TVA service are presently shut down.


North American Primary Aluminum Power Costs vs. World Average for Operating Smelters — 1983 Est.

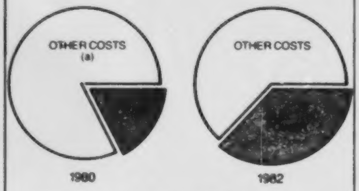
*PUBLISHED RATE PRIOR TO ADJUSTMENT

- DSI power costs have climbed more than 700 percent since 1979.


Average Price per Kilowatt Hour Charged by BPA, by Customer Group

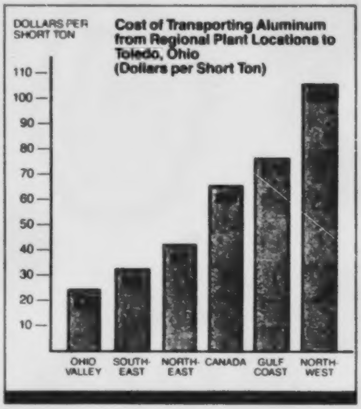
- Because electricity accounts for about one-third of the total costs of producing aluminum in the Pacific Northwest, power costs are a critical factor in determining the overall cost-effectiveness and competitiveness of plant operations.

PNW Aluminum Electric Power Costs as a Percentage of Total Production Cost



(a) *Other includes raw materials, overhead, taxes, insurance, pollution control, labor and transportation*

- In the past, the region's lower power costs offset the disadvantage of shipping DSI products from the Northwest to major markets in the East and Midwest. This competitive edge now has disappeared.



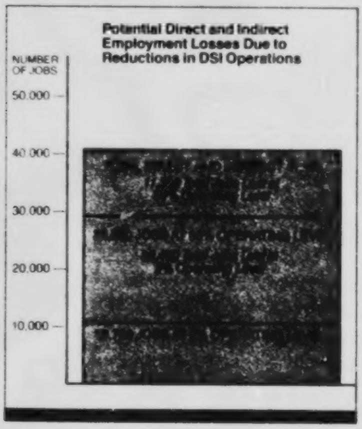
Cost of Transporting Aluminum from Regional Plant Locations to Toledo, Ohio (Dollars per Short Ton)

- Because of the effects of higher power costs on competitiveness, some Northwest aluminum plants may now be among the first smelters shut down in soft markets and the last returned to full production as market conditions improve.

Implications for the Northwest

- In 1982, because of much higher power costs and worldwide recession, DSI employment fell by about 3,500 from the 1981 level. Payroll dropped by about $67 million. Total DSI expenditures declined about $350 million.

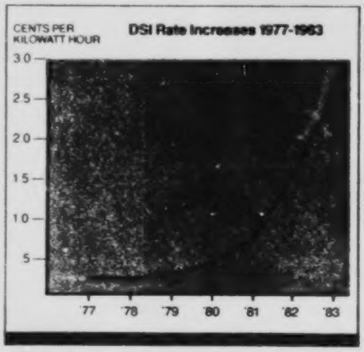
- The report points out that if the DSIs cut operations 50 percent from full operations, an average Northwest household served entirely by BPA power would have to pay up to $95 a year more for electricity through 1990. This reduction also would result in the near term loss of some 11,300 direct and indirect jobs and $50 million in taxes for the region.



Potential Direct and Indirect Employment Losses Due to Reductions in DSI Operations

- Assuming a nearly complete DSI shutdown from full operations, the report estimates a typical household served entirely by BPA power would pay up to $189 a year more through 1990. Some 30,400 total jobs would be lost in the near term, and tax revenues would decline by $136 million.

- The unpredictability and high level of recent DSI power rates have forced some aluminum companies to cancel or postpone major expansion and modernization programs.



DSI Rate Increases 1977-1983

What BPA Can Do

DSI Recommendations:

The DSIs do not seek or expect a rate subsidy from BPA, only fair treatment under its ratemaking process. DSI recommendations for ways in which BPA can achieve this goal are:

- BPA must continue to minimize its total costs to all of its customers. This year BPA trimmed over $561 million from its budgets. More emphasis must be placed on these cost-cutting measures, both short term and long term.

- BPA must allocate its costs among customers fairly and in accordance with the law. DSI rates should reflect the fact that for a variety of reasons it costs less to serve the DSIs than other customers. BPA also should recognize that it is likely to receive more total revenues from DSI power sales if BPA sets DSI rates at levels where the DSIs can operate competitively than if a disproportionate share of costs are shifted to the DSIs.

- BPA must thoroughly review the costs of the residential power exchange program that largely determine the DSI rate. BPA should administer the exchange program in a manner that carries out the intent of the Regional Power Act — to provide private utility residential customers equal access to lower cost federal power, but not to allow private utilities more advantage through the exchange than the public utility customers receive through direct access to BPA power.

- BPA should continue working aggressively to sell its present and longer-term surplus power to the DSIs and other Northwest consumers that can use the power, and to interested Southwest utilities. Power should not be sold outside the region if it can be used to provide jobs and production in the Northwest.

What You Can Do

DSI Recommendation:

If you feel the direct service industries make an important and constructive contribution to the Northwest economy and power system, please use your influence with community leaders, your congressional representatives, state legislators and other key regional officials to stress that BPA must set fair and reasonable rates for the DSIs. Fair electric rates will help keep these important industries in the Northwest.

DSI
DIRECT SERVICE INDUSTRIES, INC.
1290 LLOYD CENTER TOWER   825 N.E. MULTNOMAH ST.
PORTLAND, OREGON 97232   503 233-4445

August 8, 1983

The Honorable Al Swift
1502 Longworth House Office Bldg.
Washington, D.C. 20515

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3. More Process Doesn't Always Equate With Better Process.

Bonneville ratemaking is really the establishment of policy, not just the adjudication of ultimate facts. Congress wisely recognized this in §9(e)(2) of the Regional Power Act, which provides that "Nothing in this section shall be construed to require a[n adjudicative] hearing pursuant to section 554, 556 or 557 of the United States Code." Ratemaking is rulemaking. BPA's rate policies also must be integrated with its overall programs. An adjudicative type hearing is not the best way to make complex and interrelated policy decisions. By its nature, an adjudicative proceeding encourages parties to take extreme positions rather than working together to achieve reasonable compromises.

BPA's existing rate process already requires six to nine months of formal hearings. These hearings already tie up too many of the region's best utility executives, lawyers, economists and engineers for too long. We believe the region's time and effort could more productively be spent trying to solve the region's power problems rather than fighting over divisions of the existing power cost pie.

The requirements in H.R. 3177 to file proposed findings of fact and conclusions of law would lengthen and complicate the rate process. There is also a danger that the opportunity guaranteed by the bill to examine and refute any new evidence or studies could be misconstrued to allow an endless circle of examination even when the changes proposed by the Administrator at the end of the hearing are supported by substantial evidence on the record as a whole.

It should be noted that BPA's existing ratemaking procedures are already much more elaborate than the procedures of other Federal power marketing agencies, including the Tennessee Valley Authority. Outside of the Northwest, the trend appears to be against establishing cumbersome administrative litigation in favor of less formal legislative type hearings. Formal hearings tend to reduce the role of the general public and limit effective participation to the few parties who possess the legal and technical resources required by a formal process. (As drafted, H.R. 3177 could have this unintended result by prohibiting comments from the general public outside of the formal hearings. I have attached an amendment to the bill to preserve informal public comments.)

5. H.R. 3177 Will Not Reduce Court Appeals.

One of the laudable objectives of H.R. 3177 is to reduce judicial appeals and the resulting uncertainty over BPA rates by instilling more confidence in the BPA rate process. Unfortunately, the bill could have the opposite result. The stakes in BPA ratemaking are so great that no party can fail to appeal a decision it believes is wrong no matter how much process the party has had before BPA. Establishment of an independent Hearing Officer to make an initial decision and the requirement for findings of fact and conclusions of law encourage, not discourage, appeals to FERC and the courts by providing advocates additional arguments for review. Appeals can be reduced only if the parties are encouraged to work together to find reasonable compromises rather than being forced to take extreme positions in an adversarial process. Pacific Northwest power matters are simply too important to be left to lawyers and judges.

6. H.R. 3177 Would Open a Pandora's Box of Amendments to the Regional Power Act.

The Pacific Northwest faces a number of very serious electric power problems. All of the entities involved in regional power matters also are dissatisfied with aspects of the Regional Power Act. Consideration of H.R. 3177 could open a Pandora's box of amendments to the Regional Act. If the Act is to be reopened, it should be to deal with some of the substantive problems facing the region, in addition to any procedural problems that are not resolved by BPA, FERC or the courts in current proceedings.

Conclusion

The DSIs share your objective of trying to improve the BPA ratemaking process. But for the reasons explained above, we do not support H.R. 3177 at this time. The DSIs will continue to work with you and your staff on H.R. 3177 and the Northwest's pressing power and economic problems.

Very truly yours,

Brett Wilcox
Executive Director

PROPOSED AMENDMENTS TO H.R. 5177

Insert, as a new paragraph the following new paragraph (3) and renumber the following paragraphs accordingly:

"(3) In addition to the opportunity to submit oral and written material at the hearings, any oral or written views, data, questions, and arguments submitted by persons not a party to the hearings prior to the close of the hearings shall be made a part of the administrative record."

Amend the existing paragraph (3) and delete paragraph (4) as indicated:

"~~(3)~~(4) After the record of the hearing has been closed, the hearing officer ~~shall accord interested persons who have participated in the hearing a reasonable opportunity to file proposed findings of fact and conclusions of law respecting the establishment of rates pursuant to this section;~~ may make recommendations to the Administrator regarding any issues raised in the course of the hearings. The Administrator may reject a recommendation of the hearing officer provided that his decision is supported by substantial evidence in the rulemaking record required by this section considered as a whole.

Delete paragraph (7) and renumber remaining paragraphs.

ABILITY OF THE FEDERAL ENERGY REGULATORY COMMISSION TO CARRY OUT ITS STATUTORY AND DELEGATED RESPONSIBILITIES FOR REVIEW OF FEDERAL POWER MARKETING RATES UNDER THE CURRENT LEGISLATIVE STRUCTURE

WASHINGTON, D.C.
October 26, 1983

ATTACHMENTS

Attachment A -	DOE Delegation Order No. 0204-33
Attachment B -	Section 5 of the Flood Control Act of 1944, 16 U.S.C. § 825s. Sections 6 and 7 of the Bonneville Project Act, 16 U.S.C. § 832e and f. Section 9(c) of the Reclamation Project Act of 1939, 43 U.S.C. § 485h(c). Section 7(a)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839(a)(2).
Attachment C -	Bonneville Power Administration, Docket No. E-9563-000, "Order Confirming and Approving Transmission Rates"
Attachment D -	Bonneville Power Administration, Docket Nos. EF81-2011-000, EF81-2021-000 and EF82-2011-001, "Order Confirming and Approving Rates On A Final Basis"
Attachment E -	DOE Order RA6120.2 §8(c)(3)
Attachment F -	Western Area Power Administration, Docket No. EF80-5011-000, "Order Disapproving Rate Schedules"
Attachment G -	Western Area Power Administration, Docket No. EF80-5011-004, "Order Granting Motion And Extending Time Within Which To File Substitute Rates"
Attachment H -	Southwestern Power Administration, Docket No. EF79-4011, "Order On Reconsideration"

Attachment I - Bonneville Power Administration, Docket Nos. EF84-2011-000 and EF84-2021-000, "Order Granting Interim Approval of Rates in Part, Granting Interventions, Denying Motion For Partial Summary Disposition, And Extending Prior Confirmation of Transmission Rates"

Attachment J - Western Area Power Administration, Docket No. EF81-5021-000, "Order Disapproving Rates and Granting Intervention"

Attachment K - Bonneville Power Administration, Docket No. EF80-2011, "Order Remanding Rates Without Prejudice"

Attachment L - Bonneville Power Administration, Docket No. EF80-2011-000 (Remand), "Order Scheduling Informal Conference, Denying Motion, Granting Interventions, And Establishing Procedures"

Attachment N - Bonneville Power Administration, Docket No. EF81-2021-002 and E-9563-004, "Order Approving Extension of Interim And Final Rates"

Attachment M - Bonneville Power Administration, Docket No. EF82-2011-000, "Order Granting Interim Approval, Granting Waiver, Noting Interventions, Denying Motions, And Establishing Procedures"

ABILITY OF THE FEDERAL ENERGY REGULATORY COMMISSION TO CARRY OUT ITS STATUTORY AND DELEGATED RESPONSIBILITY FOR REVIEW OF FEDERAL POWER MARKETING RATES UNDER THE CURRENT LEGISLATIVE STRUCTURE

I. INTRODUCTION

The Federal Energy Regulatory Commission is responsible for confirming and approving power and transmission rates for the five federal power marketing administrations (PMAs). 1/ Under the current statutory and regulatory structure, rates for the PMAs other than Bonneville are developed in the first instance by the Assistant Secretary of Energy for Conservation and Renewable Energy (AS/CE), acting by and through the power marketing administrators. The AS/CE then places the rates in effect on an interim basis, 2/ and ultimately submits them to the FERC for final confirmation and approval, or disapproval. 3/

With respect to Bonneville, the rates are submitted directly to the FERC by the Bonneville Administrator for both interim and

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1/ The five power marketing administrations are the Alaska Power Administration, the Bonneville Power Administration (BPA), the Southeastern Power Administration (SEPA), the Southwestern Power Administration (SWPA), and the Western Area Power Administration (WAPA).

2/ Delegation Order No. 0204-33; 43 Fed. Reg. 60636, issued December 28, 1978 (Attachment A).

3/ Prior to the formation of the Department of Energy, the function of confirming and approving or disapproving most federal rates rested with the Federal Power Commission. After formation of the DOE, this function passed to the Secretary of Energy. See Sections 302(a) and 301(b) of the Department of Energy Organization Act, 42 U.S.C. §§ 7101, et seq. On January 1, 1979, the Secretary of Energy assigned to an Assistant Secretary and to this Commission the present statutory responsibilities.

final confirmation and approval pursuant to the statutory scheme developed under the recently-enacted Pacific Northwest Electric Power Planning and Conservation Act. 4/

The above statutory scheme and applicable delegation order regarding the PMAs place the Commission in a role very different from its traditional regulatory responsibilities. Unlike the statutory authority under the Federal Power Act or the Natural Gas Act, the power marketing statutes do not provide the Commission with any power to modify rates. Under the present scheme, should rates submitted to the Commission fail to conform to the applicable statutory standards because they are excessive, the Commission's authority is limited to that of rejecting the rates and ordering substitute rates to be filed. Pending approval of a substitute rate, the rejected interim rate remains in effect. If substitute rates are not filed within the prescribed time or if the substitute rates also fail to conform to the statutory standards, the Commission has the authority to order the last previously confirmed and approved rate to become effective in place of the disapproved rate and to order that any excess revenues collected under the disapproved rate be refunded with interest. However, if the rate has been disapproved because it is too low, the interim rate continues in effect until a higher substitute rate is confirmed and approved by the Commission. 5/

The Commission, in applying the above regulatory scheme, has encountered recurring difficulties when the rates submitted by the

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4/ 16 U.S.C. § 839e (1980).

5/ Delegation Order No. 0204-33; 43 Fed. Reg. 60636.

PMAs fail to conform with the standards set out in the relevant power marketing statutes. 6/ These difficulties, to be discussed in more detail below, range in scope from procedural problems (such as obtaining necessary data from the PMAs or attempting to reconcile our procedures with the DOE notice requirements) to substantive concerns (such as rate design questions and the "highest interest first" controversy) to remedial issues (such as the detrimental effect on the Treasury of continuing deficient interim rates in effect as a result of the failure to file an acceptable substitute rate.)

Members of the Commission staff have met with members of the DOE and PMA staffs in an effort to ameliorate some of these problems. Such efforts have met with little success to date. Problems still remain in that the legislative and regulatory scheme provides the Commission with no authority to assure that the statutory standards will be met, barring full voluntary cooperation. Furthermore, even with complete cooperation, a number of substantive and remedial questions will nonetheless remain given the narrow scope and practical effects of the Commission's authority. These concerns are addressed below.

6/ Flood Control Act of 1944, 16 U.S.C. § 825s; Bonneville Project Act of 1937, 16 U.S.C. § 832f; Reclamation Project Act of 1939, 43 U.S.C. § 485h(c); Federal Columbia River Transmission System Act, 16 U.S.C. § 838g; Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 829e. There are also a number of other statutes that relate to individual projects or systems.

II. DISCUSSION

A. Major Obstacles To Effective Commission Oversight

The principal difficulties encountered by the FERC under the present scheme fall into three categories: 1) inability of the Commission to modify rates or otherwise assure recovery of the Federal investment in the projects within a reasonable period of time; 2) purported conflicts between internal procedures followed by DOE and Power Marketing Administrations and the directives contained in Commission orders; and 3) lack of clear Congressionally-defined standards for Commission rate review. These three categories of problems are described below, with other additional problems set forth in a separate section.

1. Limited Commission Remedial Powers

As noted above, the Commission does not have the authority to modify federal rates. As a result, the Commission's remedial powers are limited to confirming and approving or disapproving the rates. This problem, which is quite significant, is one that was recognized as early as 1937 when the country's national power marketing policies were first being formulated. An early version of the Bonneville Project Act of 1937, S. 2092, had developed a division of responsibility similar to that which exists today between the Administrator and the Commission for setting federal power rates. In a letter of May 10, 1937, the Federal Power Commission (FPC), the predecessor agency to the FERC, wrote to the Senate Committee on Commerce discussing the limited review authority given to the Commission and stating that:

> [T]he bill gives the Federal Power Commission no authority to modify rate schedules submitted by the Administrator but only a veto power over the rate schedules submitted. This places the Commission in an impossible position as a regulatory agency over rates.

The letter recommended that the FPC:

> . . .either be relieved from any responsibility in connection with rates charged, or that its control over rates be made adequate, effective, and complete if, in the opinion of Congress, it should be charged with this responsibility.

Secretary of the Interior Harold Ickes, testifying on the House side on May 10, 1937, noted the FPC's objections and proposed an amendment to strengthen the FPC's authority. The last sentence of the Ickes Amendment read:

> If any rate schedule submitted by the Administrator is not approved by the Federal Power Commission, the Federal Power Commission may revise such schedule in conformity with the standards prescribed by this Act, and as so revised such schedule shall become effective.

Secretary Ickes stated that this would give the Administrator the responsibility for initiating the rate schedule and the final authority to the FPC.

However, no rate adjustment authority was ultimately given to the Commission and, as a result, the current difficulties, first foreseen as early as 1937, have resulted.

One example of the problems encountered relates to the Commission's obligations under the applicable statutes to assure that the rates recover the Administrator's costs and are sufficient to repay the U.S. investment in the projects within a reasonable period of time. 7/ Under the present statutory scheme, the Commission is effectively precluded from making such assurances. In a number of recent power marketing cases, the Commission, after finding that the rates failed to comply with the applicable statutes, exercised its authority and either rejected the rates or limited the length of the approval period while directing that new, conforming rates be filed within a specified time period. In all of these cases, the Commission was met with claims that the PMA Administrators could not or would not comply with the Commission's orders to timely file new rates. The PMAs in essence requested permission to file new rates at the time that they had intended to file them anyway, absent any Commission directive. The specifics of some of these cases are illustrative of the frustrations facing the Commission in overseeing the PMAs, given its limited authority.

Recently, two Bonneville rate cases were independently reviewed by the Commission for conformity with the applicable statutory standards. In both cases, the Commission's review resulted in a finding that the rates fell short of collecting the revenue level required to assure recovery of both the Administrator's costs and the federal

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7/ See, e.g., section 5 of the Flood Control Act of 1944, 16 U.S.C. §825s; sections 6 and 7 of the Bonneville Project Act, 16 U.S.C. §832e and f; section 9(c) of the Reclamation Project Act of 1939, 43 U.S.C. § 485h(c); section 7(a)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839e(a)(2) (Attachment B).

investment in the projects properly recoverable over that period. 8/ Prior to these findings, however, Bonneville filed new superseding rates which resulted in a locked-in period for the rates under review. 9/ Given the fact that the rates would still remain effective over the locked-in period even if they were ultimately rejected by the Commission, the Commission determined in one case that it would be "useless to reject and remand the rates to the Administrator for further development." 10/ Recognizing the adverse effect of the enforcement of the literal statutory standards in that case, the Commission concluded in its order that it would

> approve Bonneville's rates with the understanding that Bonneville will file rates to recover the revenue deficits resulting from the filing in the next transmission rate case. 11/

8/ Bonneville Power Administration, Docket No. E-9563-000, "Order Confirming and Approving Transmission Rates," 20 FERC ¶ 61,142 (August 3, 1982 (Attachment C); Bonneville Power Administration, Docket Nos. EF81-2011-000, et al., "Order Confirming And Approving Rates On A Final Basis", 23 FERC ¶ 61,378, (June 15, 1983) (Attachment D) . All FERC citations are to the Commerce Clearing House (CCH) compilation of FERC Reports.

9/ In the second case, two sets of rates, one superseding the other, were consolidated for review. Only the earlier of Bonneville's rate proposals considered in that case, therefore, was actually locked-in. The superseding rates also presented a similar problem since the Commission was informed by Bonneville that they, too, would be shortly superseded, thereby allowing little if any time for the development of substitute rates.

10/ 20 FERC ¶61,142, 61,314.

11/ Id. The Commission's understanding has yet to be realized in subsequent Bonneville filings. See Bonneville Power Administration, Docket Nos. EF84-2011-00 and EF84-2021, _____ FERC ¶_____ (October 26, 1983) (Attachment I)

The second Bonneville case is even more significant because of the magnitude of the revenue deficiency involved. The Commission there found that substantial costs of the Washington Public Power Supply System (WPPSS) were excluded from Bonneville's rates despite having been incurred during the "locked-in" effective period. The result was that Bonneville diverted other revenue resources to pay its WPPSS obligations but failed to meet its scheduled repayment of the Federal debt and deferred and capitalized interest payments of $117.8 million due that year. Moreover, the Bonneville Administrator, following DOE repayment policy, 12/ repays all operating deficits from previous years prior to making any payments of principal in the current year. This meant that none of the $164.8 million of scheduled amortization payments toward the Federal investment were made to the Treasury in 1982. Undercollection of revenues represented by failure to make interest and principal payments over the locked-in effective period was therefore over $282.6 million. Nevertheless, it would have been a meaningless gesture to reject and remand the rates to the Bonneville Administrator since the rates would remain effective over the locked-in period and higher rates, if proposed by Bonneville and approved by the Commission, could not be collected retroactively. Given the lack of a surcharge authority or rate adjustment power, the Commission's effort in carrying out its statutory mandate is clearly undercut under these circumstances.

12/ DOE Regulations, Order RA6120.2; Section 8, c(3) - Priority of Revenue Application (Attachment E).

The Commission recently evaluated the effect of Bonneville's repayment practices against a number of more acceptable repayment alternatives. 13/ Assuming a 50-year repayment schedule for federal investments in the system and use of a liberal compound interest amortization method, the Commission found that Bonneville's repayment of generation and transmission project investments was behind by more than $780 million through the end of Fiscal Year 1981. 14/ A copy of the FERC order is attached to this Report as Attachment D.

Despite making the above findings, the Commission confirmed and approved Bonneville's rates in light of several factors. For example, the rates under consideration either covered a locked-in period or would be shortly superseded, thereby providing insufficient time for the Administrator to redevelop and place into effect a revised repayment study. In addition, the Commission felt that given ample notice of its findings, prompt correction of Bonneville's repayment practices could still permit the Administrator to meet all costs and thereby conform to the requirements of the Regional Act. Nevertheless, barring such action by the Administrator, the FERC's limited remedial powers would preclude Commission assurance that overall rates will be

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13/ Bonneville Power Administration, Docket Nos. EF81-2011-000, et al., "Order Confirming And Approving Rates On A Final Basis," 23 FERC ¶ 61,378 (June, 1983).

14/ Using straight line depreciation as an alternative methodology would indicate that Bonneville's repayment is behind by $1.4 billion through FY 1981.

"sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after meeting the Administrator's other costs." 16 U.S.C. § 839e(a)(2). As discussed above, even assuming that the FERC had additional authority, demand elasticities in the Pacific Northwest area could potentially preclude the requisite "catch-up" adjustments. Given both the lack of surcharge or rate adjustment powers and the existence of significant payment deferrals, efforts to enforce the requisite statutory standards are clearly ineffective. 15/

2. Purported Conflict Between DOE and PMA Procedures and the Administrators' Stated Inability to Comply With Commission Orders

In a number of recent cases, the Commission was confronted with the question of what action should be taken in light of revenue deficiencies occurring in PMA rates. Upon ordering the filing of substitute rates that would be sufficient to recover the federal investment in one case and limiting the length of the approval period in another, the Commission in both cases was met with claims by the Administrators that the Commission's orders could not be complied with in a timely fashion because of other obligations, such as the time needed by the

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15/ The FERC was recently confronted with a similar but less dramatic case where the Southwestern Power Administration failed to keep its federal repayment obligations current. *Southwestern Power Administration, (Sam Rayburn Project)*, EF83-4021-000, "Order Confirming And Approving Rates," 23 FERC ¶ 61,403 (June 22, 1983). Given the Commission's belief that prompt correction of the problem would ameliorate SWPA's repayment deficiency, the Commission confirmed and approved the rates. However, lack of any authority to guarantee future compliance would preclude the Commission from assuring that the statutory requirements will be met.

Administrator to comply with the notice requirements of the DOE regulations or the need to develop new superseding rate filings in accordance with the Administrators' internal time schedules. Two recent cases may highlight this problem.

In a recent Western Area Power Administration case, 16/ the FERC directed the AS/CE to file substitute rates within 120 days after the Commission had disapproved the interim rates in effect as being too low to recover the federal investment. The 120-day turn-around period is expressly provided for under DOE Delegation Order No. 0204-33 (unless the Commission orders otherwise). Rather than file substitute rates, WAPA responded to the Commission's order by filing a pleading essentially requesting that the interim rates remain in effect in accordance with its originally planned time schedule, until May, 1983. The Commission, on July 2, 1982, denied the Assistant Secretary's request. Nevertheless, on August 9, 1982, the AS/CE renewed his motion to extend the period for filing substitute rates for nine months until May, 1983, which was the same time at which WAPA was already planning to file its new superseding rates. The AS/CE's request was based on the contention that WAPA would be unable to timely file substitute rates in accordance with the Commission's orders because of the time required for compliance with DOE's public notice regulations. The AS/CE also maintained

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16/ Western Area Power Administration, Docket No. EF80-5011-000, "Order Disapproving Rate Schedules," 19 FERC ¶ 61,112 (May 4, 1982) (Attachment F), rehearing denied, 20 FERC ¶ 61,008 (July 2, 1982).

that all of WAPA's rate setting staff was presently dedicating its time to a new rate adjustment which it expected to file in May, 1983. 17/ After granting a series of limited extensions in order to consider what action should be taken in light of the serious issues presented by WAPA's position, the Commission ultimately and reluctantly agreed to the AS/CE's request and effectively concluded by confirming and approving WAPA's deficient rates for the full period originally requested because no other viable alternative existed. 18/

In another case, the Commission, upon reconsideration (after initially disapproving the rates), 19/ approved the Southwestern Power Administration's proposed rates, but for one year less than originally requested by SWPA in light of a revenue shortfall occuring over the interim period that the rates were in effect. Two months prior to expiration of the rate approval period however (which was over six months after issuance of the Commission's order), the AS/CE filed a request for the Commission to extend final confirmation and approval of SWPA's rates in order to allow

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17/ WAPA also contended that its repayment study originally utilized the Bureau of Reclamation's computer program and that it no longer had access to that computer.

18/ Western Area Power Administration, "Order Granting Motion And Extending Time Within Which To File Substitute Rates," 22 FERC ¶ 61,344 (March 15, 1983) (Attachment G).

19/ Southwestern Power Administration, Docket No. EF79-4011-000, "Order Disapproving And Remanding Rates And Granting Interventions," 15 FERC ¶ 61,236 (June 3, 1981); "Order On Reconsideration," 18 FERC ¶ 61,052 (January 25, 1982) (Attachment H).

the rates to remain in effect for the full period originally requested. In support of this request, SWPA claimed that DOE's public participation requirements would preclude compliance with the Commission's "Order on Reconsideration." 20/ The Commission ultimately confirmed and approved SWPA's rates for the remaining period of SWPA's original request, although approval of the rates was based on other grounds. 21/

The above examples demonstrate the problems which the Commission has encountered in following the procedures established by the Secretary of Energy's Delegation Order No. 0204-33. The Secretary of Energy has delegated to the FERC the obligation to assure that federal rates meet the applicable statutory requirements. As noted, the Secretary established the 120-day period as a reasonable amount of time within which the PMAs could file substitute rates. Nevertheless, the Commission's orders directing that substitute rates should be filed have been almost uniformly met with requests for extensions due to other requirements purportedly imposed by the Secretary. 22/ The requests for extensions of time by the

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20/ Id.

21/ Southwestern Power Administration, Docket Nos. EF79-4011-000 and EF82-4011-000, "Order Granting Motion And Conditionally Confirming And Approving Rates On A Final Basis For Additional Period," 22 FERC ¶ 61,231 (February 25, 1983).

22/ It should be observed that despite the AS/CE's contention that the 120-day period for filing substitute rates conflicts with the Department of Energy notice requirements, the DOE Regulations arguably provide for no more than 30 days public notice for the filing of substitute rates ordered by the Commission and even this is at the discretion of the PMA Administrator, 10 CFR § 903.22(c).

AS/CE have placed the Commission in a difficult position. On the one hand, the Commission is required by the delegation order to direct the filing of substitute rates if the proposed rate is disapproved as being too high or too low. On the other hand, the Commission is being told by the Assistant Secretary that it is not possible, as a practical matter, to comply with FERC orders.

Further, the Commission does not appear to have much recourse if the AS/CE simply fails to comply with a Commission order to file substitute rates because an interim rate is too low. If the rate is disapproved because it is too high and no substitute rate is filed, the last approved rate becomes effective and refunds may be ordered. 23/ However, if the rate is disapproved as being too low and no substitute rate is filed as ordered, the interim rate apparently continues in effect. In other words, whether the Commission grants a request of the AS/CE for an extension of time or denies the request, the result appears to be much the same: the interim rate stays in effect until a new rate is filed.

There would be some impact on the PMA rates if the Commission were to disapprove the requested extensions. Many PMA customers have contracts which only permit increased rates to be placed in effect during a specific period of time or "filing window" or have contracts which the courts have found to permit no increased rates to be collected without prior approval by the Commission. 24/ In

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23/ Delegation Order No. 0204-33 (Attachment A).

24/ See, e.g., City of Fulton v. United States, 680 F.2d 115 (Ct. Cl. 1982).

this latter situation the Assistant Secretary's authority to grant interim approval of rates as provided for in Delegation Order No. 0204-33 was not recognized by the courts. A refusal to extend the Commission's approval of federal rates in these cases would presumably mean that the contract customers would not have to pay the rates beyond the period for which the rates have been approved by the Commission. This result would, however, only exacerbate in the short term the failure of the rates to recover the federal investment, which failure caused the Commission to disapprove the rates in the first place.

As a result of these circumstances, the Commission's review effort appears more and more to be a wasted effort if the PMAs continue to decline or fail to comply with the Commission's orders and the Commission lacks any effective enforcement powers.

3. Lack Of Clear Congressionally-Defined Standards For Commission Rate Review

In a number of recent cases, FERC orders have been challenged by the Power Marketing Administrations based upon claims that the Commission has either inappropriately applied or misinterpreted statutory language in its review of power marketing rates. While challenges to statutory interpretation are properly matters for the courts, in a number of cases it has been the absence of any clearly-defined rate review standards in the statutes that has resulted in delay in the review process and has led the parties to challenge the FERC's interpretion of the statutes.

The absence of clear guidance precludes the FERC from knowing whether and to what extent the Commission should be permitting the collection of power revenues for specific unconstructed projects. The lack of manifest standards has resulted in substantial expenditures of time and resources by the Commission and all parties which could be avoided with specific additional Congressional guidance. An example involving the Western Area Power Administration is illustrative.

On October 12, 1982, the Commission disapproved WAPA's rates for sales of hydroelectric power from the Colorado River Storage Project (CRSP) as being in violation of the applicable statutory standards. 25/ The Commission's disapproval was based in part upon a finding that WAPA's practice of precollecting revenues from its customers in anticipation of costs to be incurred in the construction of future power projects could not be endorsed under language of the Colorado River Storage Project Act unless WAPA could adequately demonstrate in good faith that such projects were reasonably expected to be built. Since WAPA failed to make such a showing, the Commission disapproved and remanded the rates in order to allow WAPA the opportunity to make an appropriate substitute filing, accompanied by adequate support, to be filed within 120 days. Rather than making the required filing, the Commission's

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25/ Western Area Power Administration, Docket No. EF81-5021-000 "Order Disapproving Rates And Granting Intervention," 21 FERC ¶ 61,020 (Attachment J).

order was instead met with a request on January 20, 1983, for an additional 90 days in which to file substitute rates in order to allow WAPA time to create an entirely new rate support study to be used in place of its original study. The Commission, in a February 8, 1983 order on rehearing, denied WAPA's request to file a new study in place of its original study. 26/ In light of the petitions for rehearing, however, the Commission did grant a 30-day extension to allow WAPA additional time to develop its substitute rate filing in compliance with the Commission's order.

Although WAPA's filing, inclusive of the thirty day extension, was due on March 11, 1983, WAPA instead, on March 11, 1983, filed a request for an additional ten day extension to file substitute rates. On March 21, 1983, over five months after the Commission originally remanded its filing, WAPA made a filing in purported compliance with the Commission's directive. While the Commission has not yet completed its review of WAPA's substitute filing, the rates filed are identical to the rates originally submitted to the Commission. WAPA's submittal also includes a letter from the Bureau of Reclamation that states the following:

> We do not believe the Department of the Interior is required to prove to the satisfaction of the FERC that the [future] projects. . .will be built in order to have the required funds included in the power rate.

27/ The Commission refused to allow WAPA's rate filing to become a "moving target," based upon a proposed procedure that would require the Commission to begin its review process anew and could conceivably continue *ad infinitum*.

WAPA's substitute filing thus challenges, directly or indirectly, the FERC's interpretation and, more importantly, application of the CRSP Act as part of the Commission's exercise of its rate review responsibilities. 27/

In another case, the Bonneville Power Administration challenged a series of Commission orders interpreting the rate review standards under the Bonneville Project Act and Flood Control Act. 28/ Specifically, Bonneville asserted that the Commission's attempt to review issues of rate design and cost allocation were beyond the FERC's jurisdiction under the statutes. Because the FERC allegedly lacked jurisdiction over these areas, Bonneville refused to provide the Commission with its rationale for establishing the various rate designs or to supply the Commission with any data or information supporting the designs. While this case has since been resolved, barring additional guidance from Congress, the Commission will continue to interpret and apply these statutes, and the parties will continue to challenge this interpretation and application, with neither side able to point to clear and specific ratemaking directives in the statutes on these issues.

27/ A settlement proposal was recently filed by the parties in this case which, if accepted, could obviate the immediate need to address this problem.

28/ Bonneville Power Administration, Docket No. EF80-2011-000, "Order Remanding Rates Without Prejudice," 12 FERC ¶ 61,155 (November 21, 1980) (Attachment K) ; "Order Scheduling Informal Conference, Denying Motion, Granting Interventions, And Establishing Procedures," 20 FERC ¶ 61,291 (September 1, 1982) (Attachment L).

B. Additional Problems

In addition to the problems described above, numerous other difficulties have been encountered by the Commission in attempting to carry out its statutory mandate. These problems, which are by no means insignificant, are briefly detailed below.

1. Division of Rate Review Responsibilities Between the Administrator, the Commission, and the Courts

As a result of passage of the Regional Act, procedures for reviewing Bonneville's rates are divided into three levels. A potential for delay and confusion exists under this framework and, based upon our initial experience, these procedures do not appear workable.

Under the Regional Act, the overall rate level is established in the first instance by the Administrator. The Administrator is also responsible for designing the rates and for allocating the costs between the various rate schedules. With respect to rate design and cost allocation questions, the decision of the Administrator is final except for rates developed for non-firm, non-regional customers located within the United States 29/ and for the allocation of costs between Federal and non-Federal uses of the transmission system. 30/ Thus, the decision of the Administrator on these questions is arguably directly appealable

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29/ 16 U.S.C. § 839e (k) (Attachment B).

30/ 16 U.S.C. § 839e(a)(2)(C) (Attachment B).

to the U.S. Court of Appeals. 31/ The Administrator's determinations with respect to Bonneville's overall rates, however, are submitted to the Commission for review pursuant to the three-part test established in Section 7(a)(2) of the Act. 32/ Similarly, the Commission is required to review Bonneville's non-firm, non-regional rates and, if necessary, hold additional hearings on these rates, before they become effective on a final basis.

The above framework not only has the potential to create confusion in the review process, but could potentially result in inconsistent findings by the Commission and the courts.

With respect to issues of rate design and allocation of costs between customer classes, which may be appealed directly to the U.S. Court of Appeals, the court most likely will not know whether

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31/ 16 U.S.C. § 839f(e).

32/ Section 7(a)(2) states that, except as otherwise provided for the non-firm, non-regional customers, all BPA rates are to be confirmed and approved by the FERC upon a finding that such rates:

> (A) are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power Systems over a reasonable number of years after first meeting the Administrator's other costs;
>
> (B) are based upon the Administrator's total system costs; and
>
> (C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system. 16 U.S.C. § 839e(a)(2).

those costs assigned to be recovered from the appealing parties will ultimately be approved or rejected by the Commission based upon its review of Bonneville's overall revenue requirements. Similarly, the Commission may be placed in a position of having to approve or disapprove Bonneville's overall rate level without being able to ascertain whether all or part of the rates will be rejected by the courts based upon an appeal of a particular rate design or cost allocation question. The Commission would be in a similar position with respect to the 7(k) customers since the Court of Appeals could potentially find that costs that had been allocated by the Administrator to other customers should have been properly attributable to the 7(k) customers. Accordingly, due to the interrelationship between overall revenues, rate design, and cost allocation, both the Commission and the courts could be handicapped under the review scheme set out in the Regional Act.

2. Lack of Commission Discretion in Putting Bonneville's Interim Rates Into Effect Or Extending Rates

Under the Regional Act, the Commission has the responsibility for placing Bonneville's rates into effect on an interim basis. 33/ As a practical matter, however, the Commission has little discretion to decline to place the proffered rates into effect on an interim basis because of time constraints in contractual agreements previously

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33/ For other power marketing administrations, the authority for placing interim rates into effect remains with the AS/CE.

entered into by Bonneville and its customers. These contractual commitments only permit increased rates to be placed in effect during a specific limited time period. Unless the Commission approves the Administrator's request during that "filing window," the Administrator would be legally precluded from imposing a higher rate until a subsequent filing window opens.

In a recent case, the Commission was presented with a request by Bonneville to place new wholesale power rates and charges in effect on an interim basis. The Commission's regulations require that rate schedules be filed not later than 90 days prior to the date on which the rate schedules are proposed to become effective. 34/ Bonneville's filing, however, requested that the Commission place the rates into effect within 45 days or else contractual commitments would preclude Bonneville from adjusting its rates for another year, with the result that revenues would be $815 million too low if the Commission did not act favorably. Given this choice, the Commission was effectively compelled to place the rates in effect as requested with a limited opportunity to review BPA's filing, consisting of more than 6 cubic foot boxes of materials, for compliance with the statutes and the Commission's regulations. 35/

34/ 18 CFR § 300.20(a). The Commission's regulations were since revised to provide for a shortened 60 day advance notice requirement in response to Bonneville's needs.

35/ Bonneville Power Administration, Docket No. EF82-2011-000, "Order Granting Interim Approval, Granting Waiver, Noting Interventions, Denying Motions and Establishing Procedures," 20 FERC ¶ 61,388 (September 24, 1982) (Attachment M).

In Bonneville's s 1983 submittal the filing was received by the FERC only 29 days before the requested effective date (See Attachment I).

In another case, the Commission was presented with a request by Bonneville for an extension of transmission rates on an interim basis which had previously been found by the Commission to be legally deficient but which were approved for a specified period of time on the condition that higher rates be filed. 36/ Under a similar contractual arrangement, failure to extend these rates beyond the specified period would have left the Administrator with no confirmed and approved rates for those customers. The Commission therefore granted Bonneville's request since it felt that it had little discretion left in the matter. In Bonneville's subsequent rate filing, however, the Commission, frustrated with Bonneville's refusal to comply with a FERC directive, nevertheless rejected Bonneville's transmission rates despite the fact that such rejection may preclude the Bonneville Administrator from imposing higher rates prior to the next filing window.

Because of the enormity of the consequences to the Federal Treasury of having no rates in effect, the Commission has no effective choice but to do what Bonneville asks, given these contractual commitments, or cause the Federal Treasury to forego substantial revenues. Under these circumstances the Commission

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36/ Bonneville Power Administration, Docket Nos. EF82-2011-000 and E-9563-004,"Order Approving Extension of Interim and Final Rates," 22 FERC ¶ 61,177 (February 18, 1983) (Attachment N).

cannot in good faith independently carry out its statutory mandates.

3. Inability of the Administrator to Collect Certain Rates Until Final Confirmation and Approval

Recent court decisions interpreting language in both the applicable statutes and in contracts which track the language in the statutes, if upheld, would preclude the collection of interim rates from certain customers. The language in controversy states that rate schedules are "to become effective upon confirmation and approval by the Federal Power Commission." These court decisions have interpreted this language as requiring final confirmation and approval of rates by the FERC before any new rate is permitted to be placed into effect. 37/

Since final confirmation and approval is required under this interpretation before rates can be collected, the Administrator's ability to collect sufficient revenues from these customers is jeopardized while the rates are pending before the Commission.

The Commission is thus placed in a position of having to conduct a hasty rate review in these circumstances since the revenue deficiency over the interim period increases directly with the length of time during which the rates are not placed in effect on a final basis. This creates an untenable situation when the Commission, upon review, finds that the rates do not meet the

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37/ See, e.g., City of Fulton, et al. v. United States, 680 F.2d 115, (Ct. Cl., 1982). But see United States v. Tex-La Electric Cooperative, 693 F.2d 392 (5th Cir., 1982), where the U.S. Court of Appeals for the Fifth Circuit overturned two lower court cases which had similarly held that the Assistant Secretary had no authority to place rates into effect on an interim basis.

applicable statutory criteria, or that insufficient information has been submitted to the Commission for it to undertake a reasoned analysis. Under these circumstances, rejection or remand of the rates would only exacerbate in the short term the failure of the rates to recover the federal investment. In one recent case where this situation arose, the Commission found that it had no alternative other than to confirm and approve deficient rates on a final basis in order to avoid an increasing loss of revenues by the Administrator, although approval of the rates was for a shorter period than was originally requested. 38/ In another case, 39/ the Commission was placed in a position of having to hastily publish notice of a requested SWPA rate increase, review the filing, consider public comments, and rule on the merits, because the Assistant Secretary had declined to implement the rates on an interim basis and had submitted the rates to the FERC less than one month before the requested date for final confirmation and approval.

4. Inadequacy of Power Marketing Administration Accounting Practices

The financial recordkeeping of the PMAs has presented difficulties to the Commission in assuring that PMA rates produce adequate revenues to amortize the federal investment over a reasonable period. By statute, the PMAs are obligated to repay their investments in the power projects and, in addition, to pay a portion

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38/ Southwestern Power Administration, "Order on Reconsideration," 18 FERC ¶ 61,052 (January 25, 1982) (Attachment H).

39/ Southwestern Power Administration (Sam Rayburn Dam Project), Docket No. EF83-4021-000, 23 FERC ¶ 61,403 (June, 1983).

of certain other project costs that are jointly incurred for power production and other purposes, such as irrigation. Under the statutes, non-power items such as irrigation assistance costs are to be repaid out of power revenues as a subsidy to irrigation. Because of inconsistent accounting practices used by the agencies responsible for the projects, the Commission is faced with the task of reconciling these varying approaches to determine whether the amount of investment included in the rates is appropriate.

Costs of the initial investment for facilities assigned to power are determined in most cases by the constructing agency, which is either the Army Corps of Engineers, the Bureau of Reclamation, or the International Boundary Commission. According to law, the PMAs must then repay these investments over a reasonable period of time. The amortization period to be used is 50 years or the life of the asset or, in special cases, such as irrigation projects repaid from power revenues, 60 years. (The additional 10 years relates to an initial 10-year development period for irrigation projects).

Most of the PMAs depend upon the financial records of the constructing agency and do not keep a formal set of books of their own. The constructing agencies, however, maintain their accounts based upon a depreciation accounting technique which uses a composite generation project life of about 85 years. Thus, while the PMAs typically use repayment criteria which require the investments to be amortized in 50 years, the two financial accounting methodologies cannot be reconciled when the Commission is attempting to assess the outstanding investment underlying a rate filing. This problem is exacerbated by the fact that some PMAs aggregate their project investments by general categories or by interest rate levels which makes it difficult to assess the level of repayment of individual project investments. All of these practices leave the Commission with an inadequate information base upon which to verify that repayment is being made on a timely basis.

Another accounting practice that has caused concern is the Bonneville Power Administration's practice of maintaining only one set of accounts for both its transmission system and its generating system. Under its current procedures, Bonneville does not maintain a separate accounting of costs, revenues, and deficits of the federal transmission system attributable to federal and non-federal users of the system. 40/ In order to assure that Bonneville's costs are properly identified and accounted for pursuant to the applicable legislative requirements, an accounting for the transmission system, separate and apart from the accounting for the generating system, is needed.

This system, which is not presently maintained by Bonneville, would provide a readily identifiable accounting of transmission system costs and the revenues generated from its use, along with the status of repayment of each major segment of investment in transmission facilities. Only by providing such an accounting

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40/ The term "federal" user refers to BPA's customers who receive BPA system power while the term "non-federal" user refers to customers who take transmission service (i.e. wheeling) from BPA.

can the Commission assure that the standards of sections 9 and 10 of the Transmission Act have been met, and that Bonneville's rate schedules will provide a sufficient level of revenues to Bonneville to recover its capital costs and to repay the U.S. investment in the system over a reasonable period of time. Such an accounting is also necessary to allow the Commission to reliably determine whether transmission costs have been equitably allocated between federal and non-federal users, as required by statute.

The FERC recently ordered Bonneville to establish and maintain an accounting system similar to that described above. 41/ Bonneville has chosen to regard the directives contained in the Commission's orders, however, as mere "suggestions." The FERC has therefore found it necessary to take the extreme measure of denying approval of Bonneville's 1983 transmission rate increase in light of Bonneville's failure to provide a separate accounting in accordance with the Commision's earlier order. 42/

5. PMA Project Repayment Practices

Repayment to the federal treasury of major power project investments is generally accomplished within the service life of the investment or 50 years, whichever is less. The PMAs, when establishing the level of repayment, apply a long-standing marketing agency policy, initially developed by the Department of Interior,

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41/ Bonneville Power Administration, "Order Confirming And Approving Transmission Rates," Docket No. E-9563-000, 20 FERC ¶ 61,142 (August 3, 1982).

42/ Bonneville Power Administration, _____ FERC ¶ ________ (order issued October 26, 1983), (Attachment I).

of repaying selected high interest investments ahead of the required repayment date while postponing repayment of lower interest investments. The result of this policy is to minimize the overall system-wide interest expenses being paid to the Treasury. The practice results in the Treasury's lowest interest investments remaining outstanding for periods longer than anticipated under normal amortization practices. "Amortization," as defined in the Uniform System of Accounts, requires the gradual extinguishment of principal with each interest payment by distributing the payments over a fixed period. This practice is not being followed by the PMAs. In the case of low interest bearing investments, the PMAs may repay only the interest costs while repaying high interest investments at an accelerated pace. There is arguably a serious question as to whether this policy conforms with the statutory requirement that capital investments be amortized, and not simply repaid with a balloon payment at a later date as is the present practice. While the Commission has questioned this policy in a number of cases, it has not yet acted to disapprove a rate for this reason out of deference to the long standing policy of the Department of Interior and the lack of any formal expression of concern by the Department of the Treasury. This repayment policy, however, continues to cause the Commission concern in light of its interpretation of the statutory requirements.

III. CONCLUSION

The Federal Energy Regulatory Commission has been entrusted with the oversight of federal power marketing administration rates. The legislative history of the applicable statutes reveals that the Commission was entrusted with final review responsibilities over federal rates for two reasons: 1) the Commission, being a non-regional federal agency, would be in the best position to act as a check on the Administrator's development of rate schedules based on regional needs, by reviewing the rates in light of national policies; and 2) Congress believed that the Commission, as a ratemaking body, had the strongest qualifications at a federal level to assess the propriety of the rates and charges developed in the first instance by the power marketing administrations. 43/

The Commission lacks the power to modify the rates or other remedial powers that would assure that the Commission's statutory mandate is carried out. Moreover, the lack of clearly defined Congressional standards has led to dispute as to the Commission's proper role, and resistance on the part of some PMAs to comply with Commission orders. The scheme of Commission review of federal rates has not been a workable one at this point. Even with substantial PMA cooperation, the Commission has no ability to order higher, substitute rates to be filed except prospectively. The present scheme allows the PMAs to decline to comply with the Commission's orders. Furthermore, there are additional, practical limitations on the Commission's ability to assure recovery of the federal investment in the projects within a reasonable period of time, particularly in light of declines in the rate of growth in demands for power,

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43/ *See* Remarks of May 21, 1937 of Secretary of the Interior Harold Ickes to Congress. Mr. Ickes was Chairman of the National Power Policy Committee which had formulated the Bonneville Project for implementation by Congress.

coupled with increased capital investment, particularly in the Pacific Northwest. This is in addition to the lack of Commission discretion under some circumstances to place rates in effect when the revenues appear inadequate. In the absence of adequate standards guiding the policies and practices of agencies with responsibility for rate establishment, rate review by FERC cannot be fully effective. In light of these circumstances, the Commission in 1983 echoes the sentiments pronounced by the FPC in 1937 and recommends that the FERC:

> . . . either be relieved from any responsibility in connection with rates charged, or that its control over rates be made adequate, effective, and complete if, in the opinion of Congress, it should be charged with this responsibility.

25 FERC ¶61,140

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

ELECTRIC RATES: Federal Rates

Before Commissioners: Georgiana Sheldon, Acting Chairman;
J. David Hughes and Oliver G. Richard III.

United States Department of Energy -- Bonneville Power Administration) Docket Nos. EF84-2011-000 and EF84-2021-000

ORDER GRANTING INTERIM APPROVAL OF RATES IN PART, GRANTING INTERVENTIONS, DENYING MOTION FOR PARTIAL SUMMARY DISPOSITION, AND EXTENDING PRIOR CONFIRMATION OF TRANSMISSION RATES

(Issued October 26, 1983)

On October 3, 1983, the Bonneville Power Administration (BPA or Bonneville) filed proposed wholesale power and transmission rate increases. BPA requests interim approval of these rates as of November 1, 1983, pursuant to section 7(i)(6) of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act or Act), 16 U.S.C. § 839e(i)(6), and the Commission's Rules for the Confirmation and Approval of the Rates of the Bonneville Power Administration, 18 C.F.R. Part 300. In addition, BPA concurrently requests final confirmation and approval of these rates pursuant to section 7(a)(2) of the Regional Act, 16 U.S.C. § 839e(a)(2), for the period November 1, 1983, through September 30, 1985. [1]

The proposed rates would provide for an increase in revenues of approximately $434 million over revenues which would have been collected under current rates for the twelve month period beginning July 1, 1984. 2/ In order to implement the rates as of November 1, 1983, BPA requested waiver of the Commission's 90 day advance filing requirement. 3/ According to BPA, if the rates do not become effective as of November 1, 1983, contractual limitations may prevent BPA from adjusting its rates to certain customers until several months after that date, to the detriment of the Federal Treasury.

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[1] BPA also has pending before the Commission a request for interim or final confirmation and approval of its rates for sale of power generated at the Hanford Generating Project. On August 4, 1983, in Docket No. EF83-2031-000, BPA requested an extension of the approval which had been granted by the Economic Regulatory Administration when that entity had responsibility for BPA rates. That approval expired on June 30, 1983. We have not as yet acted on the request for extension. On October 17, 1983, BPA supplemented its October 3, 1983 rate filing by requesting interim or final confirmation and approval of its Hanford rates. The Hanford rates will be dealt with in a subsequent order. No action in this order should be construed as action on the Hanford rate request.

Notice of the filing was published in the Federal Register, with comments due on or before October 20, 1983.

On or before October 20, 1983, eleven separate pleadings were filed by individual petitioners or groups of petitioners. 4/ On October 21, 1983, a late-filed motion to intervene was filed by the California Energy Commission along with separate comments in opposition to BPA's request for interim rate approval. On October 24, 1983, late motions to intervene were filed by the Northwest Environmental Defense Center, the Public Generating Pool, the Association of Public Agency Customers, and United States Representative James Weaver. Responsive comments were also filed by BPA and a group collectively referring to themselves as the Pacific Northwest Parties.

All petitioners have requested intervenor status in these proceedings. Of the sixteen sets of comments filed, most petitioners contend that Bonneville's rates do not comply with the statutory standards set forth in the Regional Act. As a result, some of the

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2/ Bonneville has requested approval of wholesale power rates which would increase power revenues to approximately $2.9 billion in operating year (OY) 1985, an increase of 17 percent over projected revenues for the same period from current rates. The proposed transmission rates would increase revenues for these services to about $96 million, an increase of about 40 percent. The rate increase to BPA's wholesale power preference customer class averages about 23.6 percent for OY 1985. The industrial firm rate increase is approximately 9 percent and the new resources rate has increased by less than one percent.

3/ See 18 CFR § 300.10(a)(3). The 90 day requirement was reduced to 60 days when the Commission issued its final rule on BPA rate review. Order issued August 9, 1983, Docket No. RM82-6-000, 24 FERC ¶ 61,161. The final rules became effective on October 17, 1983.

4/ See Attachment A for a complete list of intervenors.

petitioners have requested that the Commission disapprove Bonneville's rate schedules. 5/

Three of the petitioners 6/ contend that Bonneville's filing fails to comply with section 4(h)(10)(A) of the Regional Act which relates to the protection, mitigation, and enhancement of fish and wildlife in the Pacific Northwest. By failing to recover sufficient revenues through its rates to fund implementation of the Columbia River Basin Fish and Wildlife Program, as required by the Regional Act, the petitioners submit that Bonneville's rates are not based upon the Administrator's "total system costs," as required under section 7(a)(2)(B) of the Regional Act.

The petitioners from California (hereinafter California intervenors), 7/ have requested the Commission to deny interim approval of various aspects of Bonneville's non-firm rates for service outside the region but within the United States. California intervenors claim that Bonneville has provided insufficient support to justify approval of the non-firm and surplus power rates. Intervenors contend that these rates, particularly the NF-83 rates, are not based upon the cost of providing non-firm service, but instead are developed with an eye toward maximizing revenues from these customers and, at the same time, minimizing competition from alternative sources of supply for non-firm power to California over the Pacific-Northwest/Southwest intertie. California intervenors therefore contend that the NF-83 rate is, on its face, discriminatory and anticompetitive. The petitioners further contend that the standards for implementation of the various components under the NF-83 rate schedule are unclearly defined, leaving Bonneville with broad discretion in determining when service under the various rates will be provided. The California Utilities specifically request that Rate Schedule NF-83 be summarily disapproved by the Commission and sent back to BPA for revision and resubmission. All of the California intervenors request that a hearing be ordered on all of Bonneville's rates, including the rates governed by section 7(k) of the Regional Act.

In addition to the substantive comments noted above, the California Utilities and the California Energy Commission

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5/ Columbia River Inter-Tribal Fish Commission, California Energy Commission, California Public Utilities Commission, and the California Utilities.

6/ National Marine Fisheries Service, Columbia River Inter-Tribal Fish Commission, and the Northwest Environmental Defense Center.

7/ California Utilities, Public Utilities Commission of California, and the California Energy Commission.

object to the short time period that has been provided for the filing of comments by the parties. These intervenors point to BPA's repeated failure to conform to the Commission's advance filing regulations. The intervenors fear that, as a result of the time constraint imposed by the shortened period for comments, Bonneville has rendered the interim review and approval process meaningless. The California Utilities request that a further opportunity for comment be provided prior to final confirmation and approval of BPA's rates.

Discussion

Under Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214), the timely motions to intervene serve to make the timely movants parties to this proceeding absent opposition within fifteen days of their respective pleadings. Given the shortened comment period necessitated in these dockets, the early stage of these proceedings, and the fact that the interventions should not unduly delay the proceeding or prejudice any other party, the late-filed motions of the California Energy Commission, the Northwest Environmental Defense Center, the Public Generating Pool, the Association of Public Agency Customers, and Representative James Weaver will be granted.

As noted above, BPA has requested approval of these rates on a final basis as of November 1, 1983. In the alternative, BPA seeks interim approval as of that date. The current filing represents the second BPA request for interim rate approval under Part 300 of the Commission's regulations. In each instance, BPA has requested waiver of the 90 (now 60) day advance filing requirement, citing delays in its rate development process. Bonneville's last rates were filed 45 days before the requested effective date; the instant proposal was submitted just 29 days in advance of the proposed effective date (BPA initially requested waiver for the current rates by letter dated August 18, 1983). On both occasions, BPA has advanced the claim that, despite its substantial delay, failure to promptly implement the rates would result in a significant shortfall of Federal revenue recovery. We note that we question the justification for BPA's contractual "filing windows" which effectively compel this agency to act within whatever period Bonneville provides. However, in recognition of Bonneville's timing difficulties, the Commission has recently abbreviated the advance filing requirement to 60 days. This period must be considered an absolute minimum if the Commission is expected to undertake any meaningful review and affected parties are to be given any reasonable period in which to offer comments. In the present case, our staff has made extraordinary efforts to review a filing consisting of 8 large cartons of material in a very short time. This is an untenable situation. We recognize that BPA encountered certain unique circumstances in developing the instant rates; in particular, publication of the initial rate proposals was delayed by nearly two months to allow for an extensive reexamination of the rate proposals. Having been apprised of this delay and Bonneville's intention to seek a waiver of the advance filing requirements, our staff attempted to cooperate with BPA in order to obtain as much pre-filing information as possible. However, the waiver request and the timing of BPA's filing have substantially limited the Commission's options. While we shall reluctantly grant BPA's request for waiver in this case, we emphasize that Bonneville should take whatever steps are necessary, including review of contractual arrangements if necessary, to assure that such delay does not arise again.

Due to the complexities of the filing and the extreme time constraints placed upon the Commission by BPA's delay in filing these rates, it is impossible at this time for the Commission to make a determination with respect to BPA's request for final approval. Therefore, our current review will be limited to consideration on an interim basis which, necessarily, is a more limited review process than the review of rates for confirmation and approval on a final basis. We also shall make separate determinations with respect to the wholesale power and transmission rates for the reasons discussed below.

The Commission's regulations, in Part 300, set forth the standards to be used in considering appropriate action with respect to a request by the Administrator for interim approval of rates. Our initial review suggests that the wholesale power rate schedules proposed in the filing are developed at a level which, assuming accurate cost and revenue estimates, would produce the needed revenues to allow BPA to meet its financial obligations and to repay deficits incurred in previous years. Thus, on its face, Bonneville's system power rates appear to comply with the applicable provisions of the Regional Act. This observation, of course, is based upon the limited analysis possible in view of BPA's proposed effective date and is being made without the benefit of more comprehensive public comments and an in-depth Commission analysis. Given these time constraints, we shall deny at this time the California Utilities' request for summary rejection of the NF-83 rates. We are not persuaded by the information provided that the later availability of refunds will constitute an inadequate remedy for the concerns raised. We also find insufficient cause at this time to reject Bonneville's rates based upon the objections raised by the California intervenors or the claims relating to Bonneville's purported failure to comply with the fish and wildlife requirements of the Regional Act. These findings, however, are without prejudice to our further consideration of the issues raised in the pleadings and, if appropriate, disapproval of Bonneville's rates at a later date. A more detailed review of BPA's proposal will be conducted for purposes of determining whether the rates should be confirmed and approved on a final basis. We shall grant Bonneville's request for approval of the proposed wholesale power rates on an interim basis for a period of one year or until final approval is granted. We cannot, however, make the same conclusions with respect to BPA's transmission rates.

By order of August 3, 1982, we approved BPA's 1976 transmission rates on a final basis, but ordered BPA to implement a separate accounting of costs for its transmission system. 20 FERC ¶ 61,142. Specifically, we ordered BPA to maintain a separate accounting of revenues and deficits of the transmission system attributable to the Federal and non-Federal users. We also required BPA to provide an accounting for its transmission system separate and apart from the accounting for its generating system. That order stated:

> Bonneville shall be required to provide a readily identifiable accounting of its transmission system costs and the revenues generated from its use, along with the status of repayment of each major segment of investment in transmission facilities. Only by providing such an accounting can the Commission assure that the statutory standards of sections 9 and 10 of the Transmission Act have been met, and that Bonneville's rate schedules will provide a sufficient level of revenues to Bonneville to recover its capital costs and to repay the U.S. investment in the system over a reasonable period of time. Such an accounting will also allow the Commission to more easily determine whether transmission costs have been equitably allocated between Federal and non-Federal users. Id. at 61,315.

BPA did not seek rehearing of that order. Indeed, BPA later requested an extension of our interim approval of its 1981 transmission rates, citing attempts to comply with the August 1982 order as the basis for additional time. 22 FERC ¶ 61,178 (1983). On June 15, 1983, we approved those rates on a final basis, despite the fact that BPA had not yet initiated a system of separate accounting, since the proposed rates were developed prior to the August 1982 order. 23 FERC ¶ 61,378. We approved those rates, however, based in part upon what we construed as assurances by BPA that a separate accounting would be forthcoming in its 1983 rate filing, in accordance with our order. [8]

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[8] The Commission also found that none of the issues raised by the intervenors would have justified rejection of the rates.

BPA's 1983 filing has finally arrived, but without the separate accounting mandated. In his letter of transmittal, the Administrator explicitly states that Bonneville has not complied with our order and requests reconsideration of our directive. The Administrator states that implementation of "separate accounting would lock BPA into recovering fixed shares of transmission system costs from Federal and non-Federal customers regardless of changes in relative usage." Letter at 3. We are not persuaded by this reasoning.

Section 7(a)(2)(C) of the Regional Act expressly states that rates approved by this Commission must be found to "equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system." In our August 1982 order, we stated that such a determination cannot be made without the separate accounting information. We can no longer rely on the fact that Bonneville has had inadequate notice or opportunity to develop such information.

BPA's refusal to comply with our order precludes any type of tracking system which demonstrates that (1) transmission revenues are only used to repay transmission costs; (2) costs assigned to transmission are only transmission related costs; and (3) any deficiencies or surpluses in transmission revenues are being tracked and collected or credited to the appropriate customer class. 9/ Without this information, we cannot determine whether BPA's transmission rates satisfy the statutory requirements of the Regional Act, as well as similar provisions in sections 9 and 10 of the Federal Columbia River Transmission System Act.

On the other hand, we also have the statutory obligation to protect the interests of the Federal Treasury. Approximately one-half of BPA's transmission contracts contain a notice provision

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9/ The transmission rates at issue in this proceeding apply only to non-Federal customers using BPA's transmission facilities. Bonneville's wholesale power customers receive transmission as an unsegregated element of service under the wholesale power rates. Thus, while the distinction between generation and transmission costs is relevant, if the total cost recovery is appropriate under the power rates, this distinction is not a critical factor for purposes of our review. However, to the extent that something other than transmission costs is recovered from non-Federal users under the specified transmission rate, the allocation between Federal and non-Federal users is directly at issue.

which BPA reads as potentially precluding it from adjusting rates for a number of months if the rates are not permitted to take effect on November 1, 1983. 10/ This situation has been created by BPA in that it has negotiated contracts with these provisions and has failed to account for its filing delay under the contracts. As noted above, this situation places the Commission "between a rock and a hard place," - a situation which BPA uses to its advantage.

We believe, however, that contractual provisions, however narrowly interpreted, must not be used to force the Commission to approve rates, even on a temporary basis, when there is insufficient information to analyze the rates. Consequently, pursuant to section 300.20 of the Commission's regulations, we shall deny BPA's request for interim approval of its transmission rate filing for failure to comply with our order of August 3, 1982, and our resulting inability to find that the transmission rates comply with the applicable provisions of the Regional Act. We recognize that denial of interim approval may temporarily hinder BPA's efforts to meet its Federal repayment obligations. We cannot, however, abrogate one statutory obligation in favor of another. Based on the information provided in BPA's filing, we cannot make even a preliminary determination that the proposed rates equitably allocate the transmission costs between Federal and non-Federal customers. We note that the filed rates would increase BPA's revenues from power sales in operating year 1985 by 17 percent, while transmission revenues would increase by 40 percent. Since the Federal transmission rates are rolled into the power system rates, it would appear that the transmission rates (which apply only to non-Federal users) have been disproportionately increased. Due to the lack of accounting information, we are unable to determine whether the disproportionate increase is justified or whether this increase in transmission rates reflects an assignment of the Federal transmission revenue deficiencies from power sales to non-Federal transmission customers.

We note that BPA's current rate, as established in Docket No. EF81-2021-000, will expire as of December 31, 1983. We shall extend the current rate for a period of one year. BPA is directed to cure the deficiency in its filing by submitting the separate accounting information as soon as possible. While this may not remedy BPA's losses due to contractual limitations, it will, however, substantially mitigate its losses under all of its transmission contracts, particularly the approximately one-half which do not contain the limited adjustment notice provision.

10/ We believe that other interpretations of this contract language could be advanced although, for present purposes, we believe that Bonneville is in the best position to construe the terms of its relevant contracts.

In light of the limited time in which parties were permitted to file comments on BPA's filing, we shall allow an additional period during which parties may comment on any and all issues related to final confirmation and approval of BPA's rates. In particular, the parties are invited to comment on the need for a further hearing before this Commission.

The Commission orders:

(A) The untimely motions to intervene of the California Energy Commission, Northwest Environmental Defense Center, the Public Generating Pool, the Association of Public Agency Customers, and Representative James Weaver are hereby granted pursuant to the Commission's Rules of Practice and Procedure.

(B) The California Utilities' motion for partial summary rejection of Bonneville's WP-83 rates is hereby denied without prejudice.

(C) BPA's request for waiver of the advance filing requirement is hereby granted.

(D) BPA's request for interim approval of its transmission rates submitted in Docket No. EF84-2021-000 is hereby denied. BPA is directed to cure the deficiency in its filing by submitting the separate accounting information previously required by the Commission. Confirmation and approval of the current transmission rates, which would otherwise expire on December 31, 1983, is hereby extended for a period of one year until December 31, 1984.

(E) BPA's wholesale power rates are hereby permitted to be placed into effect on an interim basis, for a period of one year effective November 1, 1983, subject to refund with interest as set forth in Part 300 of the Commission's regulations, pending final confirmation and approval, or disapproval of BPA's wholesale power rates and charges.

(F) Within thirty (30) days of the date of this order, all parties who wish to do so shall file additional comments regarding final confirmation and approval of BPA's rates. The parties should specifically delineate in their comments any and all issues that they feel should properly be set for hearing under section 7(k) of the Act in light of the Commission's interpretation of the Act set forth in its September 1, 1982 order resolving the scope of the Commission's jurisdiction (20 FERC ¶ 61,292). All timely comments will be considered by the Commission in determining the ultimate disposition of BPA's rate proposals.

(G) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.

(S E A L)

Kenneth F. Plumb

Kenneth F. Plumb,
Secretary.

Attachment A

Filings in Response to "Notice of Filing" (issued October 4, 1983) in the Matter of Bonneville Power Administration's Wholesale Power Rates, Docket EF842011-000, and Transmission Rates, Docket EF84-2021-000

	Filing Entity	Representing
(1)	Public Power Council	A nonprofit Washington (State) Corporation consisting of 116 consumer-owned utility customers of BPA
(2)	Direct Service Industries	Aluminum Company of America ARCO Metals Company Carborundum Company Crown Zellerback Corporation Georgia-Pacific Corporation Intalco Aluminum Corportion Kaiser Aluminum and Chemical Corporation Martin Marietta Aluminum Incorporated Oregon Metallurgical Corporation Pacific Carbide and Alloys Company Pennwalt Corporation Reynolds Metals Company
(3)	Hanna Nickel Smelting Company	
(4)	Columbia River Inter-Tribal Fish Commission	Nez Perce Tribe Confederated Tribes of the Umatilla Indian Reservation Confederated Tribes of the Warm Springs Reservation of Oregon Confederated Tribes and Bands of the Yakima Indian Nation
(5)	National Oceanic and Atmospheric Administration U.S. Department of Commerce	National Marine Fisheries
(6)	Utch Power and Light Company	
(7)	Idaho Power Company	
(8)	Puget Sound Power and Light Co.	
(9)	California Utilities	Southern California Edison Co. Depart. of Water & Power, City of Los Angeles Public Service Depart., City of Glendale Water and Power Depart, City of Burbank Water and Power Depart, City of Pasadena San Diego Gas and Electric Company Pacific Gas and Electric Company

Attachment A
(Cont'd)

	Filing Entity	Representing
(10)	Public Utility Commission of the State of California	
(11)	Northwest Utilities	Portland General Electric Company Pacific Power and Light Company Washington Water Power Company CP National Corporation Montana Power Company
(12)	California Energy Commission	
(13)	Northwest Environmental Defense Center	
(14)	Public Generating Pool	Eugene Water and Electric Board City of Seattle Light Department City of Tacoma Chelan County Public Utility District Cowlitz County Public Utility District Douglas County Public Utility District
(15)	Association of Public Agency Customers	
(16)	United States Representative James Weaver	

SNAKE RIVER
HYDRO POWER

IDAHO POWER COMPANY

BOX 70 BOISE, IDAHO 83707

JAMES E. BRUCE
Chairman of the Board and
Chief Executive Officer

October 26, 1983

Mr Daniel Meek
Subcommittee on Mining,
Forest Management and BPA
1626 Longworth Bldg
Washington, D C 20515

Dear Mr Meek:

A short time ago I received a letter from Representative Jim Weaver inviting Idaho Power Company to attend the Subcommittee hearing on certain Northwest power issues.

It is my understanding that there will be representatives of the Northwest investor-owned utilities participating in this hearing and, therefore, we do not anticipate that Idaho Power Company will present any witnesses.

I have looked over the questionnaire very carefully. Since Idaho Power Company is not involved in the WPPSS plants, we do not have the expertise that many of the other utilities have with respect to the WPPSS plants and, therefore, do not feel qualified to answer your specific questions.

In addition, since Idaho Power Company does not have access to all of the BPA figures, it is very difficult for us to answer some of the other questions.

We do believe in answer to Question 3 that BPA's repayment performance can be improved by increasing their revenues and controlling their expenses. This is rather a simplistic answer, but it certainly is one that would achieve the result. In answer to Question 5, we believe that HR 3177, the proposed BPA Fair Ratemaking Act of 1983, should be adopted. In answer to Question 6, we would be in favor of the proposal requiring BPA to submit rate adjustments to FERC for confirmation and approval 6 months prior to the proposed effective date and we think that it would be appropriate for FERC to be in power to order all BPA rates increased by a uniform percentage to cover any prospective revenue for shortfalls.

We appreciate the opportunity of commenting with respect to these questions.

Sincerely,

James E Bruce
Chairman and CEO

WRITTEN SUBMITTAL
OF THE SOUTHERN CALIFORNIA MUNICIPAL UTILITIES
OF THE CITIES OF
LOS ANGELES
BURBANK
GLENDALE
and
PASADENA

TO THE
SUBCOMMITTEE ON MINING, FOREST MANAGEMENT
AND THE BONNEVILLE POWER ADMINISTRATION

JIM WEAVER, CHAIRMAN

OVERSIGHT HEARINGS ON
OCTOBER 27-28, 1983
WASHINGTON, D.C.

WRITTEN SUBMITTAL
FOR OCTOBER 27, 1983

This submittal is on behalf of the City of Los Angeles Department of Water and Power (Los Angeles), the Public Service Department of the City of Burbank, the Public Service Department of the City of Glendale, and the Water and Power Department of the City of Pasadena (hereinafter called the "Cities").

The Cities of Los Angeles, Burbank, Glendale and Pasadena operate interconnected adjacent municipal electric systems which serve the greater Los Angeles Metropolitan Area of Southern California. These utilities serve a population of approximately 3.5 million people and have combined annual sales in excess of 20.5 billion kilowatt-hours of energy. The service is rendered to approximately 1.4 million residential customers as well as 200,000 commercial and industrial customers. Our aggregate system capacity is 7,532 megawatts, with a non-coincidental 1983 peak load of 5,084 megawatts.

The areas of the Cities' written comments concern the issues of the Bonneville Power Administration's (BPA) discriminatory operating practices, the problems observed in the BPA ratemaking procedure and the Federal Energy Regulatory Commission (FERC) review process, what is viewed as incentives and impediments to interactions between the Pacific Northwest (PNW) and Pacific Southwest (PSW) regions, and, lastly, recommendations that we feel will work to the benefit of all parties.

Historical Background

Nearly two decades ago, the major California utilities, among others, and BPA, with other PNW utilities, agreed to develop and construct the two 500 kV AC and one 750 kV DC Intertie lines interconnecting the PNW and PSW. This decision was due in part to BPA's demonstration of historical (i.e., 50 years) availability of excess surplus energy, which had been initially valued at 2.0 mills/kWh, and the need for seasonal support to the PNW which could be provided by the PSW. This 2.0 mills/kWh charge for surplus energy appeared to be a reasonable recovery rate for a resource that would have been otherwise wasted by being spilled and lost to beneficial use. The availability of this surplus, which is sometimes referred to as dump energy, was one of the factors contributing to the economic justification of the intertie lines.

Since the operation of the 750 kV DC Intertie, which was later upgraded to 800 kV DC, the Cities have been customers of BPA and the other utilities in the PNW, purchasing both capacity and energy. The Cities and Southern California Edison Company are currently in the process of a further Intertie upgrade from 800 kV to 1,000 kV. The result of these upgrades is that we will increase the transfer capability from 1,440 MW to 2,000 MW. The

Cities have a 50 percent ownership entitlement in the DC Intertie, which after the upgrade, represents 1,000 MW.

In calendar year 1982 Los Angeles purchased 3,361,087 mWh of energy from BPA and the other Northwest entities, providing approximately 33.3 millions of dollars for the PNW economy.

Discriminatory Operating Practices

The sale of nonfirm energy makes a significant contribution to BPA's total revenue (estimated to be 8.7 percent in O.Y. '85). Consequently, the operating practices regarding nonfirm sales have a substantial impact on these revenue recoveries.

Through involvement in the 1983 rate hearing, Los Angeles observed that BPA operates in a self-imposed, ultra-restrictive and discriminatory manner. This ultra-restrictive operation has manifested itself in two ways.

First, during the months of October, November and December of 1982, BPA offered various amounts of nonfirm energy to the PNW. At times, the amount of energy subscribed for by the PNW was less than what BPA was offering; however, this excess energy was not offered to the PSW. Besides being a discriminatory practice, the energy not offered represents a revenue loss to BPA.

The testimony of Los Angeles during the 1983 rate hearing showed the revenue losses, from not making the excess energy available to the PSW, to be over $2,500,000 (140,000 mWh at $18.2/mWh). It is assumed that BPA would have been able to sell this energy to California utilities as energy was being purchased from the PNW at rates substantially higher than $18.2/mWh. Once BPA makes a determination that an amount of energy is surplus to the needs and desires of the PNW, there should be no reason why this energy should not be offered to customers outside of the region.

Second, the method in which BPA operates its hydro system significantly contributes to its revenue problems. If BPA had offered more energy at the Standard rate ($18.2/mWh) during the months of October, November and December 1982, and more Spill rate energy ($9.00/mWh) during January 1983 to the PSW, it could have substantially increased its revenues. For example, during the 1983 rate hearing, Los Angeles showed that during the 99-day period from October 1, 1983 (when the NF-2 rates went into effect) to January 7, 1983 (when BPA started selling Spill rate energy to the PSW on a continuous basis, which only recently ended), BPA only offered nonfirm energy to the PSW on 19 days. If energy had been offered earlier, BPA's revenues from sales to Los Angeles could have increased over 370 percent from $4,819,000 to $22,662,000.

By offering energy earlier, BPA could have also reduced the amount of water it had to spill this year. Data received during the 1983 rate hearing showed that from January 12, 1983 to April 21, 1983 BPA spilled water capable of generating over 6.3 million mWh of energy. If this energy had been sold earlier at the Standard rate of $18.2/mWh, BPA could have received revenues of over $114,000,000 more. When compared to the May 3, 1983 estimate of BPA's revenue underrecovery ($347,000,000), this loss is clearly significant. It can be argued whether all of this energy could have been sold at either the Standard or Spill rates; however, any sales that would have been made, in addition to what was actually sold, would have increased BPA's revenues and provided a clean source of electrical energy to the PSW.

Both of these situations have occurred as a result of BPA's ultra-restrictive and discriminatory operating practices. The refusal to offer excess surplus energy and the extremely limited offers of Standard rate energy to the PSW, occurred even as BPA was experiencing reduced loads in the PNW and was operating well above its own operational water levels (i.e., rule curves). These curves are used as an operating tool by BPA to assure (with a high degree of probability) that its reservoirs in the Columbia River Basin will refill.

The result of BPA's excessively restrictive operational practices causes BPA to operate in a discriminatory manner and to lose potential revenue. By not making sales earlier in the year

BPA encounters the nearly annual occurrence of spill conditions. If the reservoirs are allowed to fill to over-capacity, water must then be spilled. When this occurs, BPA must sell the energy at the reduced Spill rate instead of the Standard rate. Once the water has been spilled, the potential for clean, economical energy is lost. This energy could have replaced energy produced by nonrenewable fuels, the use of which had greater environmental impacts.

The regional discrimination does not stop with BPA's operating practices but is perpetuated by the new rates. The 1983 BPA rates improperly discriminate between the PNW and PSW by allowing the same type of energy to be sold to the same customer class at different prices. One customer may be purchasing nonfirm energy from Bonneville at the 18.5 mill Standard rate or at the 11.0 mill Spill rate at the same moment another customer is purchasing nonfirm energy at the 3.0 mill or 7.0 mill Displacement rate. The resource utilized to provide the Standard or Spill energy is the same resource that will provide the Displacement energy. BPA's California customers are virtually relegated to paying the Standard rate, while the PNW customers take advantage of the 3.0 mill or 7.0 mill Displacement rate energy. On a region-by-region or on a customer-by-customer basis, the average prices charged for nonfirm energy will have wide variations. This discrimination will be exacerbated if the current practice of allowing the PNW utilities to profit by reselling BPA energy continues.

From data supplied during the 1983 rate hearing, it appears that BPA permits PNW utilities to profit by acting consistently as conduits for resale of BPA's Standard rate energy. BPA, as the marketing agency for federal power in the PNW, has the responsibility of serving the needs of the PNW as mandated by law. Allowing PNW utilities to purchase power from BPA, then resell that same power to other utilities, is a misapplication of the spirit of the discretion delegated to Bonneville concerning sales of energy. This practice should be halted. While the elimination of these pass-through sales would not increase BPA's revenues, it would halt an inappropriate discriminatory practice.

Problems Observed In BPA's Ratemaking and FERC's Review Processes

After the close of the ratemaking hearing process, the Bonneville Administrator makes his Record of Decision. This decision is the publication of the proposed final rates. The Record of Decision and the Administrative Record are then submitted to FERC for final approval. While FERC is conducting its usually lengthy review and approval process, BPA's rates are placed in effect on an interim basis. The rates, which may or may not be found to be fair or appropriate, may cause Bonneville's customers economic harm. Prior FERC decisions concerning BPA's rates demonstrate that even though FERC was critical of Bonneville's lack of conformance with rate setting standards, it refused to set aside the rates or order a refund by BPA to the affected parties.

To rectify the shortcoming of the above process, in concept, the Cities favor a proposal that would require BPA to submit its proposed rate schedules to FERC and obtain confirmation and final approval prior to the proposed effective date. No BPA rate should be placed into effect on an interim basis.

Another problem observed during the 1983 rate hearing was the timeliness of some BPA exhibits and testimony and the relevance of data contained therein. As an example, extensive testimony and evidence was presented to support the merits of retaining the Spill rate. When the Staff Evaluation of the Record was released, the Spill rate had been retained but the policy of when to offer Spill rate energy had been radically altered. (Under the 1982 rate structure Spill rate energy is offered when BPA is in a spill or imminent spill condition, but under the 1983 rate structure, Spill rate energy will be offered only when BPA determines that it can obtain more revenue by selling under the Spill rate.) This change in policy was never discussed or testified to by BPA or any other party. Since this policy change occurred after cross-examinations and oral arguments were completed, no clarification or opportunity for cross-examination was given. This new spill policy appears to be so new and innovative that it was not adequately considered in the Final Environmental Impact Statement (EIS) released in September 1983. The timing of the release of the EIS is another example of an exhibit upon which limited questions or comments were permitted.

Perhaps the most critical observation was the apparent haste in which some BPA exhibits were created. In determining what was an appropriate Spill rate, BPA, in an effort to assure that a majority of the PNW thermal resources would get displaced, relied upon a Pacific Northwest Utility Coordinating Council (PNUCC) thermal plant costs data base. It was thought that if the Spill rate was below the variable cost of a thermal resource, spill energy would displace thermal energy. Unfortunately, BPA failed to properly analyze the components of these thermal costs and used data which included fixed costs such as rent, landscaping and maintenance of the grounds, and plant security.

Los Angeles pointed out this error in its rebuttal testimony and analyzed the quantitative impact as much as possible. As a result, the Spill rate was reduced by 2.0 mills/kWh. Los Angeles suggested that BPA perform an extensive analysis on true variable costs of PNW thermal facilities. This suggestion was not acted upon.

One final problem observed during the 1983 rate hearing was that Bonneville claimed that its nonfirm rates were based upon the cost of providing nonfirm service. However, Bonneville has never performed a cost-of-service study to identify the costs which are incurred in providing such nonfirm service. As a result, confusion and uncertainty were created in the 1983 rate hearings when discussing nonfirm rates. The hearing presentations were reduced to mere speculative arguments as to what constitutes reasonable cost components for such nonfirm energy rates.

Impediments and Incentives to Interactions Between the PNW and PSW

The proposals to increase the interregional transmission capacity between the PNW and PSW, including the recently revived proposal to develop the second phase of the 1,000 kV DC Intertie line (i.e., between Celilo, Oregon and Mead, Nevada) could be impeded by recent BPA operating practices and poli[illegible] decisions. These impediments are detailed in the following discussion.

A review of the nonfirm rates, since the Cities have been Bonneville customers, indicates that the cost of spill energy has increased from 2.0 mills/kWh to 9.0 mills/kWh by 1982 with no apparent additional costs incurred or identified for such service. This is a 350 percent rate increase. The 1983 rates proposed by the Administrator call for a charge of 11.0 mills/kWh for Spill and 18.5 mills/kWh for Standard energy rates. With no guarantee that spill energy will be offered to the PSW, the Cities may be paying 18.5 mills/kWh for the same energy that back in 1970 was purchased for 2.0 mills/kWh. This is over an 800 percent rate increase. This volatility of nonfirm energy rates is discussed and demonstrated in Appendix 1.

Besides the energy rates, BPA has increased the normal cost based intertie transmission rates and proposed a separate Southern Intertie access charge for non-BPA energy. This charge does not reflect actual costs incurred for providing the service, but appears to be designed solely for revenue enhancement. These types of proposals or threats cause the PSW to question the economics of any future long-term PNW transactions.

Even though the Cities recognize the proclivity of the PNW utilities to promote policies and activities to maximize the use of nonfirm energy in the PNW, it is viewed as another impediment to increased interregional interactions. Both BPA and the Pacific Northwest Electric Power and Conservation Planning Council (Council) by their words and actions* have shown that utilities outside the PNW should not expect nonfirm energy to be available as it has been historically. If BPA allows its customers to replace firm energy commitments with less expensive nonfirm energy, as appears to be the case with the DSIs special nonfirm sales, BPA may not recover as much revenue as it could. The Cities do not mean to imply that expanding the nonfirm energy market in the PNW is improper; however, they wish to illustrate the fact that it dampens the enthusiasm of the parties in the PSW to expend funds for any additional increase in the PNW/PSW Intertie capacity.

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*In the Administrator's Record of Decision for the 1983 rate proposal, at page 389, it is stated that "BPA is striving to expand its market for nonfirm energy in the Northwest" (emphasis added). BPA has also recently made offers and sales of nonfirm energy to the DSIs, irrigators and industries which have dual-fueled boilers or other alternative fuel source capability. Charles T. Collins, a Council member from Washington, indicated, during the October 4, 1983 meeting of the PNW/PSW Surplus Sales Workshop in San Francisco, that it was the Council's intention to determine in-region (PNW) markets for nonfirm surplus, thus reducing any competition between surplus firm and surplus nonfirm sales.

Perhaps the most ironic impediment is that the same laws which were meant to protect the PNW, now are making it difficult for the PNW to take advantage of the regional surplus by increasing sales to the PSW. For example, long-term purchase commitments, which would replace planned or existing generating resources, cannot be relied upon with assurance by the PSW utilities because of the short-term recall provisions (i.e., 60 days for energy and 5 years for capacity) mandated by the Regional Act (Public Law 88-552). These provisions are interpreted by BPA to allow temporary or permanent suspension of commitments, thus creating uncertainty as to the future availability of the pledged resources.

Notwithstanding the above impediments, given the proper incentives, the Cities would like to continue to conduct business with, and thus contribute to the economy of the PNW. Realizing the anticipated abundance of available surplus energy, the seasonal and daily load diversity and the prospects of a truly cost-of-service based nonfirm energy rate structure, there are financial benefits that are available to both regions from continued and increased interactions.

Recommendations

In view of the preceding discussion, the Cities offer the following recommendations:

1. That BPA should re-evaluate its operating procedures concerning the timing and amount of nonfirm sales. In particular, a new study should be initiated of the Columbia River Basin, its various reservoirs, dams and electrical facilities, to determine the optimum manner of system operations;

2. Amend statutory requirements, such that once the availability of surplus energy has been declared by BPA, such surplus energy shall be offered first to the PNW and then shall be mandatorily offered to the PSW on the same terms as was offered to, but declined by, the PNW utilities;

3. As an alternative to No. 2 above, Bonneville should be required to request the Solicitor's Office of the Department of the Interior, or Congress should request the U.S. Attorney General's Office, to clarify that portion of the Regional Act (i.e., Public Law 88-552) concerning surplus energy as to

when and by what terms it can or should be exported from the PNW region;

4. That FERC's final approval be obtained by BPA prior to implementation of any new rates, including interim rates;

5. That FERC should require BPA to establish rates based upon actual costs incurred to supply energy to each customer class; and

6. That BPA base its entire revenue requirement recovery on its firm energy sales and utilize any revenue realized from nonfirm sales to offset any deficits, apply as a rebate adjustment to all of its customer classes after its Federal Treasury payment requirements have been met, or accelerate payments to the Treasury.

APPENDIX 1

The rate volatility, briefly mentioned in our testimony under the section of "Impediments and Incentives to PNW/PSW Interactions", has been extremely dramatic when observed over the past ten years (i.e., 1974 through September 1983).

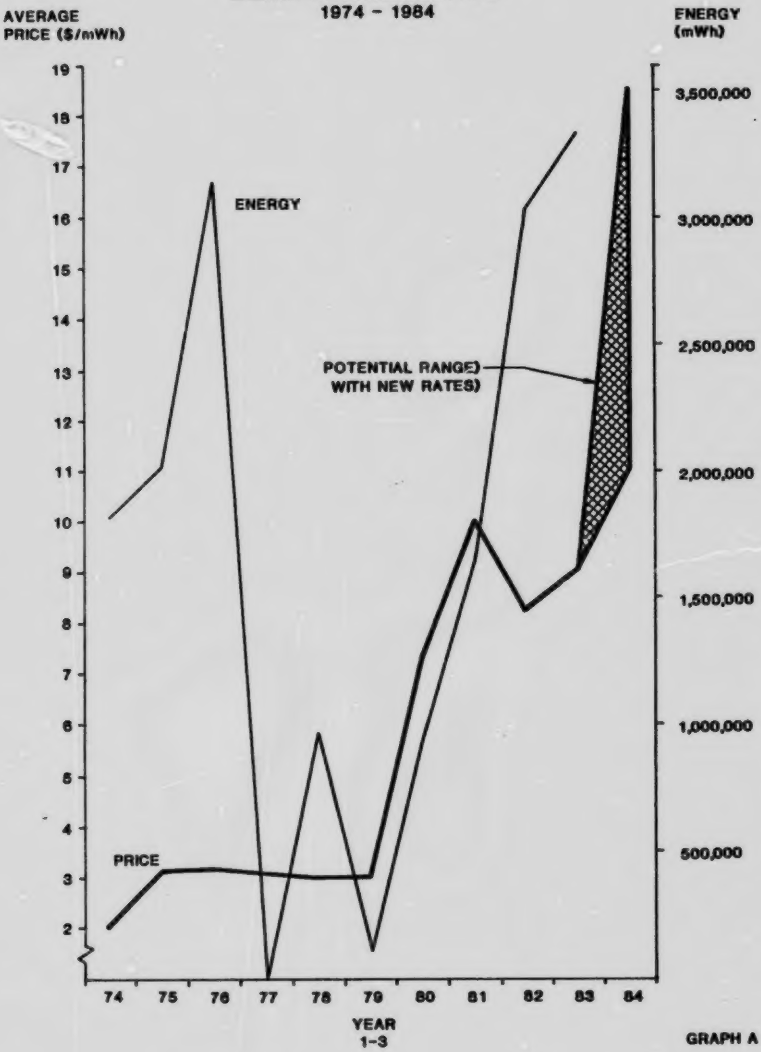
Table A tabulates the BPA nonfirm rates, the amount of on-system nonfirm energy purchased by Los Angeles, and the average price paid. The amount of energy purchased and its average price for year 1984 cannot be estimated until some experience is gained as to how BPA will operate under its new spill policy. However, it is assumed that Los Angeles and the Cities will never be offered energy at either of the Displacement rates.

Graph A represents a plot of the data from Table A.

TABLE A
PNW ENERGY AND AVERAGE PRICE
1974 - 1984

YEAR	RATE ($/mWh)		ENERGY (mWh)	AVERAGE PRICE ($/mWh)
1974	2.0		1,814,458	2.0
1975	3.0 3.5	4/75 - 8/75 9/75 - 3/76	2,024,064	3.12
1976	3.0 3.5	4/76 - 8/76 9/76 - 3/77	3,139,390	3.18
1977	3.0 3.5	4/77 - 8/77 9/77 - 3/78	0	--
1978	3.0 3.5	4/78 - 8/78 9/78 - 3/79	964,475	3.01
1979	3.0	4/78 - 8/78	104,713	3.0
1980	H-6 "Share the Savings" typical price range of 4.5 - 15.0		939,046	7.22
1981	H-6 and NF-1 Melded rate typical price range of 4.5 - 31.3		1,621,324	10.05
1982	NF-1 and NF-2 18.2 Standard 9.0 Spill		3,032,318	8.23
1983 (through Sept.)	NF-2 18.2 Standard 9.0 Spill		3,328,989	9.0
1984	Proposed rates 18.5 Standard 11.0 Spill New Spill rate policy		"?"	11.0 - 18.5

ENERGY AND AVERAGE PRICE
1974 - 1984



GRAPH A

RESPONSE TO QUESTIONS POSED TO THE CALIFORNIA UTILITIES AND AGENCIES

SUBMITTAL OF THE SOUTHERN CALIFORNIA
MUNICIPAL UTILITIES OF THE CITIES OF
LOS ANGELES
BURBANK
GLENDALE
and
PASADENA

TO THE
SUBCOMMITTEE ON MINING, FOREST MANAGEMENT
AND THE BONNEVILLE POWER ADMINISTRATION

JIM WEAVER, CHAIRMAN

OVERSIGHT HEARINGS ON
OCTOBER 27-28, 1983
WASHINGTON, D.C.

QUESTIONS POSED BY CONGRESSMAN WEAVER FOR CALIFORNIA UTILITIES AND AGENCIES

QUESTION 1

BPA's final studies for the 1983 rate proposal show that BPA expects revenue from surplus firm power sales to increase from $28 million in FY 1983 to $186 million in Operating Year (OY) 1985. Is this a reasonable projection of the additional revenue BPA can expect to obtain from surplus firm power sales to California?

RESPONSE 1

The Los Angeles Department of Water and Power (Los Angeles) presently has an existing Exchange Agreement in place with BPA whereby BPA makes 525 MW of Exchange Capacity available to Los Angeles and Los Angeles pays for this capacity, not with money, but by delivery of Exchange Energy at the rate of 2,500 kWh/kW-year. This Agreement was in effect in 1983 and will terminate in July 1986. Thus, Los Angeles has not contributed any, nor foresees any contribution in OY 1985, to BPA's estimated revenues to be derived from surplus firm power sales.

QUESTION 2

BPA's final rate studies also show that BPA anticipates revenue from nonfirm surplus energy sales to California to increase from $150 million in FY 1983 to $201 million in OY 1985, even though BPA expects nonfirm surplus energy sales to California to decline from 1932 average megawatts (aMW) in FY 1983 to 1635 aMW in OY 1985. This implies a nonfirm surplus energy rate increase to California of 58%--BPA expects 34% more revenue from 15% lower sales. Is this a reasonable projection of the additional revenue BPA can expect to obtain from nonfirm surplus energy sales to California?

RESPONSE 2

From October 1982 through September 1983 Los Angeles purchased from BPA 3,609,096 mWh of Spill rate energy ($9.0/mWh) and 53,615 mWh of Standard rate energy ($18.2/mWh) for use in Los Angeles. These purchases provided BPA with $33,457,657 of revenue from nonfirm sales. If these same amounts of energy were purchased in OY 1985 under the new rates ($11.0/mWh for Spill and $18.5/mWh for Standard) the revenue to BPA would be $40,691,933, or an increase of 21.6 percent. The possibility exists that BPA may never offer energy at the Spill rate as a result of the new spill policy. If this occurs and Los Angeles purchases the same total amount of nonfirm energy, the revenue to BPA will be $67,760,153 or an increase of 102.5 percent.

The preceding analysis shows that an increase of 34 percent in nonfirm revenues from California is possible; however, Los Angeles cannot determine whether this is a reasonable projection. To achieve this increase BPA will be required to sell a larger proportion of its nonfirm energy at the Standard rate rather than the Spill rate. At the Standard rate there will be more utilities who have rates to compete with BPA in the surplus energy market. As a result, Los Angeles and the Cities of Burbank, Glendale and Pasadena may purchase energy from other utilities or utilize their allocations of energy from other PSW resources, such as coal facilities, while BPA may be spilling water. Without the knowledge of what kind of energy market BPA will be competing against or how the new spill policy will be implemented, an estimate of increases in BPA's revenues from nonfirm energy sales cannot be made with any reasonable degree of certainty.

QUESTION 3

Overall, BPA expects to collect $387 million from the California utilities in OY 1985, if it is assumed that the California utilities are the market for BPA's surplus firm power sales. This compares to total BPA revenue from California of about $178 million during FY 1983 (excluding firm capacity purchases) and appears to be an increase of about 117%. Can BPA realistically expect to recover this much additional revenue from the California utilities?

RESPONSE 3

For the reasons given in our responses to questions one and two above, an estimate of the total amount of revenue BPA can realistically expect from California during OY 1985 cannot be made with any reasonable degree of certainty. However, since Los Angeles and the Cities do not expect to contribute to BPA's revenues from surplus firm sales, all revenue increases will have to be from nonfirm sales.

QUESTION 4

What control over BPA's budget and expenditures is available to BPA's customers?

RESPONSE 4

There is no control over BPA's budget and expenditures available to BPA's customers except through Congressional review of BPA's budget. During the rate hearing, BPA's total revenue requirements and budget components are subject to review and comment with limited influence and no control. Revenues to finance budget items are derived from various rate schedules developed during BPA ratemaking hearings. During these hearings, questions arise as to whether or not a given expenditure item should be paid from a given rate schedule. It is only in this indirect way that BPA customers have an opportunity to have any input concerning BPA's budget and expenditures. It should be noted that in such situations, the approval of budget items is never at issue. Rather, it is only the source of revenues to pay for the proposed expenditures that is subjected to questions.

QUESTION 5

What suggestions do the California utilities have for improving BPA's repayment performance?

RESPONSE 5

BPA should stop relying on nonfirm revenues to help meet its revenue requirements. BPA should instead plan to meet its revenue requirements solely through firm transactions. This would result in revenue stability even in critical water years. Revenues from nonfirm transactions could then be used to make up any revenue deficiencies, provide a rebate adjustment to all customers or be used to accelerate payments to the Treasury.

QUESTION 6

What is the position of the California utilities on H.R. 3177, the proposed BPA Fair Ratemaking Act of 1983?

RESPONSE 6

At the present time Los Angeles and the Cities are still reviewing the implications of H.R. 3177 and have not yet formulated a position.

QUESTION 7

Would the California utilities favor a proposal requiring BPA to submit rate adjustments to FERC for confirmation and approval 6 months prior the proposed effective date, if FERC were (1) required to complete its review (both under Regional Act § 7(a)(2) and § 7(k)), based on the record in BPA's proceeding, within the 6-month period, and (2) empowered to order all BPA rates increased by a uniform percentage to cover any perceived prospective revenue shortfalls?

RESPONSE 7

Item (1) concerning a specified time frame for FERC's review and confirmation of BPA rates prior to such rates becoming effective are considered to be generally acceptable concepts. However, specific details and alternative suggestions are still under active consideration by Los Angeles and the Cities, and a more comprehensive response will be developed in the future.

Item (2) concerning the proposal to empower FERC to order a uniform percentage increase of all BPA rates to cover prospective revenue shortfalls, perceived during a FERC review period, is being reviewed, and Los Angeles and the Cities have not yet formulated a position on this suggestion.

QUESTION 8

How much nonfirm surplus energy did BPA sell to the California utilities during August 1983? September 1983? October 1983? Were the California utilities during any of these months willing to pay BPA's present NF-2 Standard rate (18.2 mills/kWh) for this energy? Did BPA offer such NF-2 Standard rate energy to the California utilities during each of these months?

RESPONSE 8

During the months of August, September and October 1983, Los Angeles purchased the following amounts of surplus energy from BPA to serve its loads.

Month (1983)	Amount (mWh)	Rate ($/mWh)
August	289,688	9
September	15,084	9
October (as of 10/20)	0	-

In August and September, Los Angeles purchased 11,395 mWh and 37,067 mWh, respectively, from the Pacific Northwest at rates higher than the 18.2 mills/kWh Standard rate. If BPA had offered energy at the Standard rate, Los Angeles would have displaced the other, more expensive Northwest purchases. The data for October is not yet available; however, the trend of increasing prices for Northwest energy and reduced BPA sales is continuing. It is logical to assume that if BPA were making energy offers at the Standard rate in the current energy market, Los Angeles and the Cities would be making purchases.

BPA has made no offers of nonfirm Standard rate energy to Los Angeles or the Cities in August, September, or October 1983.

QUESTION 9

What are the California utilities' present plans for expanding transmission capacity between the Northwest and California? Have these plans progressed since the Subcommitte's hearing on transmission in Eugene, Oregon, on July 11, 1983? Do the California utilities agree with the recommendation of the U.S. General Accounting Office that, if no agreements for substantial

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intertie expansion have been reached within 1 year, the Secretary of Energy should direct BPA and WAPA to seek congressional approval to develop the most cost-effective intertie additions?

RESPONSE 9

At the present time, the DC Intertie line is being upgraded from 1,600 MW (800 kV) to 2,000 MW (1,000 kV). This upgrade is scheduled for completion in January 1985. Other than this upgrade Los Angeles and the Cities have no plans for further expansions or new construction on the Pacific Northwest/Southwest Intertie. The position of Los Angeles and the Cities is that at the present time it is not economically justifiable to expand or add to any intertie capacity. The reasons for this position are elucidated in our testimony and written submittal. If the economic justification is not reasonable for the Southwest utilities to build any additional intertie capacity, Los Angeles and the Cities, at this time, do not recommended that government agencies undertake the development of such additions.

QUESTION 10

What policies should BPA adopt to determine which Northwest utilities shall have access to the Pacific Intertie for making power sales to California?

RESPONSE 10

Los Angeles and the Cities believe that the 1974 Federal Columbia River Transmission System Act requires BPA to make available to all utilities, in the Pacific Northwest, Intertie capacity on a fair and nondiscriminatory basis. This requirement should act as guidance to BPA when allocating to other Northwest utilities the transmission capacity that is not needed to market its own power. BPA should not adopt policies that could be designed or interpreted to impede competition among the PNW utilities in accessing the PSW markets.

WPPSS NUCLEAR PROJECT #3

WHERE NOW?

A REPORT TO

NORTHWEST CONSERVATION ACT COALITION
Box 20458
Seattle, Washington 98102

and

NATURAL RESOURCES DEFENSE COUNCIL
25 Kearny St.
San Francisco, CA 94108

DRAFT FINAL REPORT

October, 1983

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COST OF COMPLETION AND OPERATION OF WPPSS #3

ABSTRACT

THE COST TO COMPLETE AND OPERATE WPPSS #3 IS MUCH GREATER THAN REPORTED BY THE BONNEVILLE POWER ADMINISTRATION OR THE NORTHWEST POWER PLANNING COUNCIL.

THEIR ANALYSES HAVE TENDED TO UNDERESTIMATE THE CONSTRUCTION COST TO COMPLETE THE PROJECT, UNDERESTIMATE THE FINANCING COSTS ASSOCIATED WITH COMPLETION, AND UNDERESTIMATE FUEL COSTS. IN ADDITION, BONNEVILLE HAS OVERESTIMATED THE PLANT OPERATING LIFETIME.

BASED UPON THREE ALTERNATIVE ASSESSMENTS, OPTIMISTIC, MOST LIKELY, AND PESSIMISTIC, THE COST OF COMPLETION AND OPERATION OF WPPSS #3, MEASURED IN LEVELIZED 1980 DOLLARS, RANGES FROM 45 MILLS/KWH TO 74 MILLS/KWH, AT THE BUSBAR. IF PROJECT #3 IS BROUGHT INTO SERVICE PRIOR TO THE TIME IT IS NEEDED, AND THE POWER SOLD AT LESS THAN THE COST OF PRODUCTION, REGIONAL RATEPAYERS WILL BEAR AN ADDITIONAL BURDEN WITH AN EXPECTED VALUE OF UP TO 27 MILLS/KWH.

ON A DELIVERED BASIS, INCLUDING TRANSMISSION COSTS AND LOSSES, THE COST IS ABOUT 20% MORE. IF EXTERNAL COSTS, INCLUDING FEDERAL SUBSIDIES TO THE NUCLEAR INDUSTRY, AND ENVIRONMENTAL COSTS, ARE ADDED THE TOTAL COST OF POWER FROM WPPSS #3 EXCEEDS 100 MILLS/KWH (1980 LEVELIZED $) IN ALL SCENARIOS.

THE "OPTIMISTIC" ESTIMATE IS APPROXIMATELY 60% HIGHER THAN THE ESTIMATE DEVELOPED FOR THE NORTHWEST POWER PLANNING COUNCIL BY BATTELLE PACIFIC NORTHWEST LABORATORIES IN APRIL, 1983; THE "PESSIMISTIC" ESTIMATE IS APPROXIMATELY THREE TIMES THE ESTIMATE THEY HAVE USED.

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SUMMARY OF FINDINGS

The cost to complete and operate WPPSS #3 cannot be ascertained with any degree of confidence, due to the unpredictable nature of nuclear costs in general, and to the unpredictable future of project #3 in particular. A range of estimates can be made of the cost of completion and operation, which will provide a guide as to the possible outcomes of a decision to complete, or to attempt to substitute other resources for the projected output of this project.

WPPSS has published numerous different estimates of the capital, fuel, and operation and maintenance costs for project #3. The wide range of WPPSS-provided estimates lends credibility to the notion that the cost to complete and operate the project is largely a matter for speculation at the present time.

This analysis consists of three different analyses of the potential output cost from completion of project #3. A base scenario uses data produced primarily by WPPSS, selected to reflect a plausible estimate of ultimate power cost. An "optimistic" analysis uses data produced primarily by WPPSS and by Bonneville, but selected from among the lowest estimates of each possible cost component. Finally, a "pessimistic" analysis uses assumptions taken from sources other than WPPSS in some instances, to reflect the impact that circumstances WPPSS is not planning for would have on the project cost, including the potential for adverse cost-sharing settlements with WPPSS #5, changing regulatory requirements, and potential operation and maintenance costs.

It is generally accepted that deferral, including demobilization and remobilazation will increase the cost of completion of project #3; the August 10, 1983 revised construction cost estimates reflect these delay costs. The cost of delay, of course, must be measured relative to the cost of early completion, or the prospect of completion when termination may be the best option, in low-growth scenarios, for example. One cost of early completion would be the payment of interest penalties on borrowed funds, a cost which could be expected to subside once present legal difficulties are resolved, so long as the resolution provides for continued payment of principal and interest to net-billed bondholders.

Another cost of early completion would be losses to regional ratepayers associated with the sale of WNP-3 power outside the region at less than the full cost of production, and the need to replace the project after a shorter period of use to meet in-region sales if a portion of the operating lifetime were committed to out-of-region sales.

The table below shows the results of the three scenarios:

Incremental cost to Complete and Operate WPPSS 3

TABLE I-1

TOTAL COST FOR WPPSS #3
1980 LEVELIZED MILLS/KWH

	OPTIMISTIC	BASE CASE	PESSIMISTIC
DIRECT COSTS			
Busbar cost:	45	56	74
Loss from surplus:	19	24	27
Subtotal:	64	80	101
EXTERNAL COSTS			
Subsidies	21	21	21
Environmental	20	20	20
Subtotal:	105	121	142
Transmission:	5	5	5
Losses @ 9%:	10	11	13
TOTAL:	120	137	160

OTHER STUDIES

Three other major studies of the cost to complete and operate project #3 have been undertaken in the region recently. This analysis will evaluate each of these, and compare the results of this analysis with that of each of the alternatives. A summary of the three analyses, and the basic assumptions contained therein are shown below:

COST EFFECTIVENESS STUDY OF WNP-2 AND WNP-3, Applied Economics Associates, February, 1983

This study was undertaken to satisfy the requirements of Initiative 394, which has since been determined to be inapplicable to WPPSS with respect to units 1-3; the study used data from both WPPSS and independent sources. A cost to complete of $1.4 billion was used, exclusive of interest during construction or opportunity costs associated with the use of ratepayer capital, together with an assumed 60% capacity factor and a 30 year plant lifetime.

Fuel costs were estimated primarily from WPPSS-supplied data, as were O&M costs.

The estimated levelized cost to complete and operate in this analysis (1982 $) in this analysis was 34 mills/kwh, or about 32 mills/kwh in 1980 $.

ASSESSMENT OF ELECTRIC POWER CONSERVATION AND SUPPLY RESOURCES IN THE PACIFIC NORTHWEST: NUCLEAR (VOLUME XIV), Battelle Pacific Northwest Laboratories, April, 1983

Battelle assessed the costs to complete project #3 under contract to the Northwest Power Planning Council. A cost to complete of $872 million, exclusive of interest during construction or opportunity costs associated with the use of ratepayer capital, together with an assumed 60% capacity factor, 65% availability factor, and a 40 year lifetime. The cost to complete used by Battelle measured only costs expected to be incurred after January, 1984, and is agreed to be inapplicable to the present circumstance, with major construction work halted in May, 1983.

Incremental cost to Complete and Operate WPPSS 3

Fuel costs were estimated primarily from WPPSS-supplied data, as were O&M costs. These fuel costs are significantly lower than those reported in the May, 1982 WPPSS Official Bond Statement.

The estimated levelized cost to complete (1980$) in this analysis was 25 mills/kwh, or about 27 mills/kwh (1982$)

FIRST YEAR COST AND REAL LEVELIZED COST TO COMPLETE AND OPERATE WNP-3, Bonneville Power Administration, July, 1983

Bonneville analyzed the cost to complete and operate project #3 based upon an assumed $961 million cost to complete the Supply System 70% share of project 3. A 65% "equivalent availability factor" was substituted for a capacity factor estimate, and a 35 year plant life was used, together with fuel and O&M cost data supplied by the Supply System. The fuel costs used were taken from WPPSS Action Memorandum #24, and are significantly lower than those reported in the May, 1982 Official Statement An escalation rate for fuel and O&M costs of only .5% was used, compared with much higher escalation rates assumed by other analysts.

Unlike the other analyses, Bonneville calculated annual nominal costs for all years of project operation, and explicitly discounted those costs to present value. Other analyses took "shortcuts" by estimating costs in constant dollars. This analysis uses the same method used by Bonneville.

The estimated levelized cost to complete (1982$) in this analysis was

Incremental cost to Complete and Operate WPPSS 3

30 mills/kwh, or about 27 mills/kwh in 1980$.

TYPES OF COST ASSOCIATED WITH COMPLETION AND OPERATION

The following costs of completion and operation must be analyzed in order to estimate the cost to complete and operation project #3:

Capital costs: Capital costs must include the direct construction costs to complete the project, together with the interest during the construction period of carrying those costs. In the case where interest during construction is paid from Bonneville rates, the opportunity cost to ratepayers of providing that capital must be included.

Fuel costs: Two aspects of fuel cost must be calculated; first, the amount of fuel required, based upon heat conversion efficiency and estimated burnup rates; second, the cost per unit of fuel, including anticipated escalation during the project lifetime.

Fuel disposal: Passage of the Nuclear Waste Policy Act requires a payment of 1 mill/kwh from all operating nuclear plants to pay for federal waste disposal; there is no assurance that this cost will not be either increased or decreased in the future to reflect actual costs. In addition, there is the prospect that general tax revenues may be used to subsidize fuel disposal if costs exceed the revenues provided by the 1 mills/kwh levy. While the expected costs have been included in each of the estimates of fuel cost, there is a contingent liability for an addition, unknown amount.

O&M costs: Estimates of project O&M costs, including anticipated inflation and escalation must be calculated.

Capital Additions: Equipment at the projects must be replaced as it wears out, and new rregulatory standards must be met. WPPSS has separately estimated the cost of replacements; the escalation rates should be similar to those for O&M costs.

Taxes: Both publicly and privately owned nuclear projects are subject to taxes; in the case of project #3, the privately owned portion is subject to property tax; this is included in the private utility portion of the annual fixed charge factor. The public portion of WPPSS #3, and 100% of of project #1, are subject to an in-lieu-of property tax assessment, now established at .2 mills/kwh.

In addition, power sold at retail in Washington and Oregon is subject to an excise tax of 3-6%, this is not included in any of the assessments of project completion cost.

Decommissioning: Under the terms of the site certification agreement with the state of Washington for project #3, WPPSS is obligated to decommission the project at the end of the operating period, and to restore the site. In each of the scenarios analyzed, the decommissioning costs assumed by WPPSS in their Action Memo #24 were used; in the pessimistic scenario, these costs were arbitrarily doubled to reflect potential adverse developments.

For ease of analysis, escalation in the cost of fuel, O&M, capital additions, taxes, and decommissioning occurring during the two year delay necessitated by the current construction deferral at plant #3 have been ignored in this analysis. As the only estimates WPPSS has published of these costs are for a series of years beginning in 1987, these cost streams were analyzed assuming a 1987 startup of the project. The deferral, while clearly causing some increases in some of these costs, will have an uncertain effect. As a conservatism, this study uses the 1987 costs for the 1989 operating year, the 1988 costs for the 1990 operating year, and so forth.

In additon, in comparing the cost of completion and operation of project #3 to resources providing energy at the point of consumption, transmission costs and losses must be factored; under the terms of the Northwest Power Act, conservation resources are to be analyzed using a 10% preference. The Northwest Power Planning Council has determined that these costs are offset by administrative costs associated with the development of decentralized resources. While this study includes these costs in the ultimate analysis, they are not a part of the threshold at which alternate resources are determined to be cost-effective in comparison with WPPSS #3.

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II
CAPITAL COST OF UNIT #3

The capital cost to complete project #3 differs widely in various studies done of this plant. Battelle assumed a total cost to complete of only $872 million; AEA assumed a cost to complete of $1.4 billion; Bonneville assumed a current WPPSS estimate of $961 million for the Supply System 70%, which translates into $1.37 billion for the total plant, essentially the same as AEA, in spite of the fact that AEA based it's estimates from February, 1983 on, while BPA ostensibly used June, 1983 as their base; about $100 million was spent on the project in the intervening months.

All of these estimates cover only direct construction costs; Interest during construction has been excluded. To fully analyze the cost to ratepayers of resuming construction, interest rates on borrowing must be determined, and the interest during the construction period on the remaining expenditures included. Interest on the existing WPPSS #3 debt is to be ignored, as these costs are considered to be already committed (legal action may change the party responsible for bearing these costs, but will not change the cost itself.)

One area the three cited studies have ignored are the shared costs now in dispute between WPPSS plant #3 and plant #5. The legal arguments surrounding this litigation center on the assertion that plant #3 is receiving 100% of the benefits of the shared costs, and should therefore bear 100% of the costs themselves. If plant #3 were terminated, neither plant would receive any benefit, and the basis of the argument would be irrelevant. Since the costs of WPPSS 4/5 are not being borne by ratepayers, while the costs of WPPSS #3 are, completion of WPPSS #3 would expose ratepayers to the shared costs, while termination of #3 would likely eliminate that risk. Therefore, it is proper to consider the retroactive cost sharing to be an avoidable cost of completion for WPPSS #3.

Given the fact that construction has been demobilized, in part, on project #3, the most optimistic estimate of the direct construction cost to complete is not the "1984 budget" published by WPPSS in July, 1983, but rather the August 10 estimates for completion. This document [Analysis of Cost/Schedule impacts of WNP-3 Extended Construction Delay, Washington Public Power Supply System, August 10, 1983] identifies four different completion scenarios.

Case 1 assumes a January, 1984 restart, and avoids the need to first totally demobilize, and then remobilize the work force, by halting the continuing decline. Case 2 assumes a July, 1984 restart, with completion in 1989. Case 3 assumes a July, 1985 restart, with completion in 1990; Case 4 also assumes a July, 1985 restart, but provides for a slower construction pace, with completion in 1991.

Given the lack of regional consensus, the withdrawal of necessary legislation, the need for court testing of whatever

Capital cost

financing arrangements might be chosen for completion of WPPSS #3, and the statements of the WPPSS Executive Board Chairman to the Northwest Power Planning Council, this analysis assumes that a July, 1984 restart is the most optimistic possible construction schedule for the project. While a longer delay may be advisable, and perhaps inevitable given financing problems, an optimistic assumption is appropriate for determining the lower limit of reasonable project costs for an analysis of project costs for completion under present circumstances.

The 1984 construction budget is the base document for the August 10, 1983 construction cost estimate. The 1984 budget assumed a cost to complete the project of $1.36 billion in direct construction costs for the total plant, or about $960 million for the Supply System 70% share.

WPPSS has reported other estimated costs to complete project #3. In the 5/82 Official Statement, a remaining financing cost of $1.162 billion was reported for the Supply System 70% share, (page 6). In addition, there is the issue of cost sharing, which WPPSS identifies in the 1984 budget as a $269 million contingent liability.

This totals over $1.4 billion for the Supply System 70% share, or $2 billion for the total project; this is about 40% more than the WPPSS 1984 budget. Interest during construction must be added to the direct construction costs.

Their is a $200 million difference between the WPPSS estimate used in the 1984 budget (in turn the basis for the August 10 estimates) and that reported in the Official Statement is unexplained by WPPSS. The 1982 budget for plant #3 contained a contingency of $365 million; the 1984 budget contains only a $222 million contingency.

It would appear prudent to include the $200 million difference, and assume some probability of the cost-sharing lawsuit being successful if construction is resumed on project #3, as costs to complete the unit. The Base Case analysis assumes that the cost-sharing settlement, if #3 is completed, will equal $200 million in 1983 dollars, and that the costs to complete plant #3 will total $200 million more than the August 10 "Case 2" construction costs, to account for the discrepancy between the Official Statement and the 1984 budget. The "optimistic" analysis excludes these two adjustments, using the direct construction costs to complete directly from the August 10 WPPSS estimate; the "pessimistic" case assumes the same capital cost estimate as the "base" case, but applies different estimated operating costs, as detailed in other sections of this analysis.

AVAILABLE

Capital cost

FINANCING COST -- INTEREST DURING CONSTRUCTION

In each case, interest during construction must be added to the direct construction costs for the project. Table II-1 and II-2 detail the direct construction costs associated with project #3 on an annual basis, and the interest during construction associated with carrying that construction cost through the construction period. Table II-1 excludes any adjustment to the WPPSS August 10, 1983 estimates; Table II-2, used for the base and pessimistic cases, includes a $200 million allowance for cost-sharing (1983$) and an additional $200 million to account for the discrepancy between the cost to complete in the Official Statement and that in the 1984 budget. This may be thought of as a restoration of the contingency removed in the 1984 budget.

Interest during construction has been assumed at 13% for the public utility portion, and 15% for the private utility portion. These rates are consistent with current capital costs for both WPPSS and the four private utilities. While private utilities often report lower "AFUDC" rates than this, they generally compute these on a "melded" basis -- averaging all debt issues, including existing low-cost debt -- in identifying a weighted average cost for the debt portion of AFUDC. In fact, of course, it is incremental, not average, costs which would be avoided if construction were terminated.

Battelle and AEA both assumed that the financing for project #3 would be available at a rate of 3% above the rate of inflation, and included this "real" interest during construction in the cost of the project. In today's market, financing is considerably more expensive that this.

The present long-term tax-exempt utility revenue bond rate is approximately 12-13%; if conventional financing were available to WPPSS, this is the cost which would be incurred for their 70% portion of the project. Taxable private utility financing is even more expensive. Equity returns authorizations to the Washington and Oregon private utilities are 16% to 18%; their debt and preferred rates are now 13% to 14%. This means that the average cost of capital to private utilities is about 15%.

The financing rate assumed by AEA and Battelle is inappropriate, considering current circumstances. Presently, inflation is running at an annual rate of only 4%; that suggests that tax-exempt bonds are yielding 8-9% real, and taxable financing is about 11% real. Even assuming a long-run rate of inflation, as specified to AEA in their contract with WPPSS, of about 6%, interest during construction is 6-7% real for WPPSS, and 9% for private utilities.

Capital cost

Bonneville used a bond rate of 12-13% for WPPSS, similar to this study, and a private AFUDC rate of 12.15%, which is clearly too low in today's market. This AFUDC rate appears to reflect average, rather than incremental capital costs for private utilities.

The total cost of construction, to the date of completion, therefore is a combination of direct construction cost and AFUDC. In the case of the WPPSS 70% share of #3, interest during construction is paid out of BPA rates, rather than capitalized. As a result, in calculating the total incremental cost, both the BPA revenues, and the opportunity costs to ratepayers of providing those revenues must be considered.

Bonneville, AEA, and Battelle have totally ignored the cost to ratepayers of providing the revenues which it is collecting during the construction period. Estimates of consumer discount rates have been made, both in the Northwest and in other regions, and have been shown to average 35%-60%, based upon market activities of consumers (Purchasing Patterns of Energy-Efficient Refrigerators and Implied Consumer Discount Rates, Alan Meier, LBL, August, 1982) This analysis assumes an opportunity cost of ratepayer-provided capital equal to the average cost of capital to WPPSS and the private utilities. The average of 70% at 13% and 30% at 15% equals an overall cost of interest during construction for the project (regardless of whether it is provided by ratepayers from current rates, or by utilities from the capital market) of 13.7%; the Northwest Power Planning Council used a 10% opportunity cost of consumer capital in evaluating their proposed building code in the development of the Regional Plan; this is equivalent to a 16% nominal opportunity cost, meaning that this analysis is conservative.

The table below shows the assumed direct construction costs, the interest during construction, and the total on-line ($1989 $) incremental costs for project #3 under each of the three scenarios.

TABLE II-1

OPTIMISTIC SCENARIO; BPA CASE 2

COST ELEMENT	TOTAL COST (MILLIONS)
WPPSS BONDS	1417.50
IOU BONDS AND STOCK	607.50
AFUDC (TOTAL)	1171.24
TOTAL COST TO COMPLETE:	3196.24

CALCULATION OF AFUDC ON TOTAL CONSTRUCTION COSTS (CAPITALIZED)

YEAR	CONSTR EXPENSE	CUM CONSTR	CUM CONSTR + AFUDC	AFUDC @ 13.7%
1983(6 MOS)	114.00	114.00		7.81
1984	125.00	239.00	246.81	33.81
1985	348.00	587.00	628.62	86.12
1986	696.00	1283.00	1410.74	193.27
1987	486.00	1769.00	2090.01	286.33
1988	244.00	2013.00	2620.35	358.99
1989 (6 MOS)	12.00	2025.00	2991.33	204.91
TOTALS:	2025.00			1171.24
	BALANCE AT COMPLETION:			3196.24
	1980 Cost/kw:			1617.00

TABLE II-2

OPTIMISTIC SCENARIO; BPA CASE 2 SHARED COSTS AND CONTINGENCY ADDED

COST ELEMENT	TOTAL COST (MILLIONS)
WPPSS BONDS	1697.50
IOU BONDS AND STOCK	727.50
AFUDC (TOTAL)	1520.81
TOTAL COST TO COMPLETE:	3945.81

CALCULATION OF AFUDC ON TOTAL CONSTRUCTION COSTS (CAPITALIZED)

YEAR	CONSTR EXPENSE	CONTINGENCY & SHARED ($400 TOTAL)	CONSTR EXPENSE	CUM CONSTR	CUM CONSTR + AFUDC	AFUDC @ 13.7%
1983(6 MOS)	114.00	211.26	325.26	325.26		22.28
1984	125.00	12.35	137.35	462.60	484.89	66.43
1985	348.00	34.37	382.37	844.98	933.68	127.91
1986	696.00	68.74	764.74	1609.72	1826.34	250.21
1987	486.00	48.00	534.00	2143.72	2610.55	357.65
1988	244.00	24.10	268.10	2411.81	3236.29	443.37
1989 (6 MOS)	12.00	1.19	13.19	2425.00	3692.85	252.96
TOTALS:	2025.00	4000.00	2425.00			1520.81
			BALANCE AT COMPLETION:			3945.81
			1980 Cost/kw:			2004.00

2/88

Capital cost

TABLE II-3

TOTAL CONSTRUCTION COST PLUS AFUDC

	OPTIMISTIC	BASE/ PESSIMISTIC
BOND RATE (PUBLIC)	13%	13%
(PRIVATE)	13%	13%
EQUITY RATE (PRIVATE)	17%	17%
AVERAGE RATE FOR AFUDC	15%	15%
DIRECT CONSTRUCTION COST	2025	2425
INTEREST DURING CONSTRUCTION	1171	1521
TOTAL ON-LINE COST (1987$)	3196	3945

The costs above will be used in the three scenarios to determine overall life-cycle costs. Annual carrying charge rates for each scenarios will determine the annual capital cost of the projects; operating costs can then be added, an annual total project cost determined, and explicitly discounted to present value using the life-cycle costing methodology presented by Bonneville in their testimony before the House Interior Committee.

These estimated costs differ significantly from those used by the Northwest Power Planning Council in draft analyses of WPPSS #3, largely in that they explicitly include all interest during construction at market-determined rates. In addition, the Council staff has assumed a January, 1984 restart of the project. Given current financing difficulties, the Supply System's unwillingness to proceed without assurances that the project can be financed to completion, and Bonneville's failure to adopt rates sufficient to finance even interim construction without risking default, this study assumed that this was impractical.

The annual carrying charge rate for the public portion of the project is a simple amortization of the incremental capital cost over the project lifetime. For the private utilities, property taxes and depreciation must be added. Property taxes

Capital cost

are assumed to be charged to the private utilities at 1% per annum. A 3.33% annual straight line depreciation schedule has been assumed; while utilities use accelerated depreciation for tax purposes, which boosts profits, these benefits are not flowed through to ratepayers. As a practical matter, this tax benefit is a part of the cost of equity capital which is not included in the estimate in Table II-3. Absent this tax benefit, the equity market would demand an equal return from ratepayers. Internalization of this cost would increase the cost to complete WPPSS #3.

The annual charge factor for the private utility financing is developed based on a formula submitted by Pacific Power and Light to the Oregon PUC in December, 1981; the cost rates have been reduced slightly to reflect modest improvements in the market:

TABLE II-4

PRIVATE UTILITY ANNUAL CHARGE RATE COMPUTATION

	SHARE OF FINANCING	COST RATE	WEIGHTED VALUE
DEBT:	50%	13%	6.50
PREFERRED:	14%	15.5%	2.17
EQUITY	36%	17.2%	6.19
AVERAGE COST OF CAPITAL:			14.86
LEVELIZED RETURN:			11.70
LEVELIZED INCOME TAX:			2.85
LEVELIZED FIXED CHARGE:			14.55
DEPRECIATION (STRAIGHT LINE; 30 YEARS)			3.33
PROPERTY TAX:			1.05
INSURANCE:			.40
TOTAL ANNUAL CHARGE FACTOR:			19.33

The annual charge factor for a public utility is identical to the amortization, on a compound mortgage basis, of the capital cost. The two annual charge factors can be weighted into a single figure for simplicity in calculating regional annual costs. The appropriate annual charge factors are shown below:

Capital cost

TABLE II-5

COMPOSITE ANNUAL CHARGE FACTOR FOR PROJECT #3

Public Utility:	13.34%
weighting:	70%
Private Utility:	19.33%
weighting:	30%
ANNUAL CARRYING CHARGE: (Weighted average)	15.14%

Bonneville used a much lower annual carrying charge for the private utilities, which follows their use of average, rather than incremental, costs of capital. In a recent rate filing, the Washington Water Power Company disclosed estimated annual charge rates for their current thermal projects; these range from 18.5 to 21%. (Record Requisition #13 & #16, WUTC Cause U-83-26). Water Power is probably the healthiest of the four investor-owned utilities involved in WPPSS #3, as it has the lowest investment in deferred and terminated nuclear plants, and therefore should be expected to have lower than average costs of capital.

ANNUAL AMORTIZATION COST OF CAPITAL INVESTMENT

Multiplying the investment at completion, including interest during construction, by the annual carrying charge of that investment yields the annual revenue requirement to discharge the capital investment. For the three cases above, the annual revenue requirement for the incremental cost to complete project #3 is shown below; note that these are expressed in levelized nominal dollars. These costs are discounted to present value, and to levelized constant dollars, on Tables VII-1 through VII-3.

TABLE II-6

ANNUAL REVENUE REQUIREMENT
PUBLIC AND PRIVATE SHARES COMBINED

OPTIMISTIC	$438,874,400
BASE CASE	$507,424,400
PESSIMISTIC	$507,424,400

Capital cost

INTEREST PENALTIES ON WPPSS AT PRESENT

Due to present uncertainties about WPPSS financing, including the possibility of bankruptcy, outstanding WPPSS bonds are presently yielding a substantial premium on the market. It is to be expected that any securities issued in the immediate term to finance the project, backed by a Bonneville revenue pledge, would be subject to this penalty, since a major source of the uncertainty is Bonneville's authority to underwrite the WPPSS projects in the first place.

At October 6, the interest yield on WPPSS 1/2/3 bonds (reported by the Wall Street Journal) was approximately 16.5%; the interest yield on other long-term joint action agency revenue bonds (IPA, NCarolina, MMWEC) was approximately 12.0%, or 450 basis points lower. Voter approved bonds are yielding 10-10.5%.

Assuming that the projects were financed in the present market, through a new entity, this 450 basis point penalty would be incurred; if a 5 year term on a short-term credit instrument were assumed, the present value of the penalty associated with $1 billion in borrowing at this penalty rate is approximately $100 million. If long-term issues are assumed, the present value of the penalty is approximately $400 million.

A three year delay period, coupled with resolution of the underlying legal questions in favor of bondholders, would erase much, if not all, of the financing penalty.

A reasonable comparison, therefore, is between the added direct construction costs of delay, and the financing penalty associated with moving forward on the present schedule. The Nuclear Task Force (page 32) estimated the cost of delay at $25 million per year; this is substantially smaller than the interest penalties associated with a 5 year issue, and about one-fourth of the interest penalty associated with a long-term issue.

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III
FUEL COSTS

The three studies of the cost of completion and operation of project #3 reached significantly different conclusions regarding the cost of fuel for the project, in spite of reliance on Supply System data for their analyses. This is due to different estimates of the amount of fuel required, different fuel cost escalation rates, and different estimates of initial fuel cost.

All of the studies estimated much lower costs for fuel than reported by WPPSS in the last Official Statement. Bonneville, in addition, used an extremely low rate of fuel and O&M cost escalation.

Battelle and the Power Council Nuclear Task Force concluded that an initial annual fuel cost of $24.1 million would be needed for project #3 fuel plus .8 mills/kwh for waste fuel disposal, for a total of $29 million per year. This translates into about 5.4 mills/kwh. With real escalation at the rate estimated by Battelle over the life of the project, the levelized fuel cost using these assumptions equals $39.1 million, or about 7.4 mills/kwh levelized.

Battelle has assumed a cost of uranium of $1052/kg (including sales tax) PAGE 4.17; this compares with estimates as high as $1661/kg (before tax) in independent assessments. The Nuclear task force assumed a cost of $1379/kw. Both the nuclear task force and Battelle assumed a higher fuel use efficiency than appears to be reasonable, of 33,000 MWDt/MTU. The average fuel utilization rate for Pressurized Water Reactors is only 24,000 MWDt/MTU (Historical Survey of Fuel Utilization in U.S. LWR Power Plants, Southern Science Applications, August, 1979 DOE/ER/10020-TI Page 2)

Bonneville based its fuel cost assessment on the data in WPPSS Action Memorandum #24 for the year 1987-92, and then escalated these at .5% real for the remainder of their assumed 35 year plant life. This assumption results in an estimated 6.9 mills/kwh levelized fuel cost. Bonneville bases their use of a other analysis appears to support the use of this escalation rate. The WPPSS Action Memorandum fuel costs, escalated at 1.5% real has been used in the optimistic case study; this is detailed in Table III-2.

By comparison, the fuel costs assumed in the May, 1982 Official Statement for the period 1987-92 are nearly twice as great as in Action Memorandum #24 for the years 1990-92. During the period 1988-92, these costs escalate at approximately 11% nominal, or 5% real. If these fuel costs are escalated during the years after those shown in the Official Statement [1992] at the 1.5% rate used by Battelle, a levelized fuel cost of 12.5 mills/kwh (1980$) obtains. This cost has been used in the base case, and in the pessimistic case; it appears in Table III-3.

Fuel Cost

A 5% real rate of escalation over the plant life, similar to that assumed by WPPSS for the initial six years of operation in the Official Statement, would suggest a 17.81 mills/kwh levelized fuel cost. This higher figure may be representative of costs which will occur in the future.

Independent assessments of nuclear fuel costs have been carried out by the Department of Energy, by the Regional Power Council Nuclear Task Force, and by other interested analysts. These all appear to show fuel costs uniformly higher than used by Battelle and Bonneville. The table below includes both the estimates from the studies conducted in this region, and those from independent sources:

TABLE III-1

COMPARISON OF FUEL COSTS
1980 levelized mills/kwh
(Regional Studies)

	ESCALATION RATE	LEVELIZED COST 1980 MILLS/KWH
BATTELLE	1.5%	7.4
BONNEVILLE	.5%	6.9
ACTION MEMORANDUM #24	1.5%	7.3
OFFICIAL STATEMENT	1.5%	12.5
OFFICIAL STATEMENT	5%	17.8
	(Generic Studies)	
U.S. DOE		8.5
Komanoff Energy Associates		12.0
Ebasco Services		16.3

TABLE III-2

ESTIMATE FUEL COST/KG (before taxes)

Battelle:	$1052	
Nuclear Task Force:	$1379	
AEA:	$1571	(disposal and inventory costs added; Nuclear Task Force estimates used
Komanoff Energy Associates:	$1661	
Department of Energy	$1634	

CURRENT FUEL CONTRACTS

WPPSS has a contract for supply of uranium concentrates from Exxon Nuclear for a fourteen year period beginning with the original on-line date for WPPSS #2 (1977). WPPSS indicated it had won a "victory" when litigation upheld this contract, which Exxon sought to have declared invalid. This should make the fuel costs, for the initial period, easily identifiable, and below market prices. However, the fourteen year period would appear to end in 1991 -- still within the period for which specific fuel costs are shown in the Official statement.

If, indeed, WPPSS did "win" the Exxon Nuclear lawsuit, it would imply that fuel costs will rise sharply after 1991. The 1.5% real escalation assumed in the base case, therefore, may significantly understate the fuel costs which will actually be experienced.

Unfortunately, WPPSS has reported two different fuel cost streams for the project -- one in the May, 1982 Official Statement, and the other in the October, 1982 Action Memorandum; the latter estimate is significantly lower than the former, suggesting a drastic reduction in anticipated fuel cost.

The existence of a 14 year below-market fuel contract suggests that beginning in the 15th year of the project operating life, that a one-time jump in fuel costs should occur. However, AEA appears to predict exactly the opposite, concluding that fuel prices would drop sharply in the 15th year, and then resume slow escalation. This would appear to imply that WPPSS really won nothing, and in fact is being held to a fuel supply contract at above-market prices.

WPPSS has a significant amount of fuel on hand for project #3, which has been paid for out of previous bond sales. As early as September, 1978, the uranium needed for initial core loading had been delivered to WPPSS by Allied Chemical (Official Statement of 9/78; page 13). This fuel presumably has a market value in the event of plant termination. AEA identified the value of the fuel on-hand at $61 million. If the Exxon Nuclear contract is assignable [if the Supply System has the right to take delivery of the fuel at the contract price, and resell it at market value] there is an additional salvageable asset.

NORTHWEST NUCLEAR REFUELING SCHEDULES

In the Northwest, refueling will generally be carried out each Spring, more or less regardless of need. For example, the Trojan plant was refueled in April-July of 1983, in spite of the fact that it had operated only five months on the 1982 fuel load. This is done to insure that nuclear units are capable of operating throughout the Winter period.

Refueling generally takes place in May and June, during the runoff period. The months of September-November are typically the periods with the least surplus energy, nuclear plants can be expected to be operated throughout this period. This means that they MUST have a full fuel load in order to operate at full capacity for the seven month period from September through March, when their output is most likely to be needed. Even if the output is not needed in February and March, once water conditions are better known, it is necessary to refuel in the Spring to protect against adverse conditions the ensuing Winter.

The Regional Council's Strategic Analysis Model (SAM) incorporates an extremely low variable operating cost for nuclear plants -- less than 2 mills/kwh. As a result, the model attempts to operate nuclear units whenever possible, leading to an artificially high capacity factor assumption under most water conditions. However, the SAM does recognize that the nuclear units must be refueled on a particular schedule, regardless of the amount of energy actually produced in the preceeding year.

The 1983 experience with Trojan confirms the above analysis. Trojan was taken out of service (for economy reasons) in January, 1983, after plentiful snowpack ensured availability of hydro generation to meet all anticipated loads. The unit was refueled in the Spring, and returned to service in late July. It is entirely possible that it will again operate only five to six months on this fuel load.

This circumstance is unique to the Northwest, where nuclear units may be taken out of service for economy reasons when hydro conditions make sufficient energy available to meet all loads. A hydro "glut" will depress surplus sales rates. Economy shutdowns of thermal plants help to control the supply of surplus energy, and therefore bolster surplus rates. For this reason, an analysis of surplus water conditions is instructive in determining what proportion of the time nuclear units can be expected to be removed from service for economy reasons, forcing the replacement of unexpended nuclear fuel. This analysis is provided in the section of this analysis on "Surplus Power Impact on WPPSS #3 Cost."

That analysis shows that approximately 25% of the time surplus hydro availability exceeds the capability of the regional intertie, forcing the shutdown of thermal plants for economy purposes. In addition, given a 1000 MW or more firm surplus, operation for displacement of existing coal plants to provide power for export would be be expected to occur 35% of the time in which thermal plants are assumed to operate (thermal plants are assumed to be out of service in May and June, when fish flow requirements and natural streamflows provide expectations of sufficient hydrogeneration; scheduled maintenance is planned during these months. At such times, the market value of WNP-3 energy is only equal to the avoided fuel costs of a coal plant.

TABLE III-3

[illegible] AL DOLLAR ANALYSIS OF WPPSS #3 FUEL COSTS [illegible] [illegible]

YEAR	FUEL COST $ NOMINAL	OUTPUT MILLION KWH	NOMINAL POWER COST MILLS/KWH	CONSTANT $ COST/KWH DEFLATED @ 6%	PRESENT VALUE OF COSTS @ [illegible]
1987	52032357	6517	7.99	7.99	52032357
1988	63542020	6517	9.75	9.20	55197472
1989	67944265	6517	10.42	9.30	53988927
1990	71832657	6517	11.02	9.25	55134254
1991	79335714	6517	12.17	9.64	55833398
1992	85932257	6517	13.20	9.85	55456045
1993	92425321	6517	14.19	10.00	54602719
1994	99421722	6517	15.25	10.15	53762525
1995	106878343	6517	16.40	10.29	52935851
1996	114894225	6517	17.63	10.43	52120719
1997	123511253	6517	18.95	10.58	51318714
1998	132774633	6517	20.37	10.73	50528251
1999	142732737	6517	21.90	10.88	49751539
2000	153437693	6517	23.54	11.04	48985950
2001	164945510	6517	25.31	11.19	48232221
2002	177315434	6517	27.21	11.35	47490851
2003	190615155	6517	29.25	11.51	46759321
2004	204911384	6517	31.44	11.68	46039795
2005	220279651	6517	33.80	11.84	45331351
2006	236800825	6517	36.33	12.01	44633829
2007	254560672	6517	39.06	12.18	43947928
2008	273652723	6517	41.99	12.35	43270736
2009	294176677	6517	45.14	12.53	42604359
2010	316239928	6517	48.52	12.70	41949368
2011	339957922	6517	52.16	12.88	41302395
2012	365454765	6517	56.07	13.07	40668334
2013	392863874	6517	60.28	13.25	40042583
2014	422328664	6517	64.80	13.44	39426481
2015	454023314	6517	69.66	13.63	38819729
2016	486353553	6517	74.63	13.82-	38222392
TOTAL:	6183265351	AVERAGE:	31.62	11.29	

[illegible] REAL ESCALATION   SUM OF PRESENT VALUE: 1438511619

AMORTIZATION OF PRESENT VALUE @3% 73101545

LEVELIZED COST OF POWER: 1987 MILLS/KWH 11.22

1982 MILLS/KWH 8.39

1980 MILLS/KWH 7.46

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TABLE III-4

NOMINAL DOLLAR ANALYSIS OF WPPSS #3 FUEL COSTS D.S. FUEL03

YEAR	FUEL COST $ NOMINAL	OUTPUT MILLION KWH	NOMINAL POWER COST MILLS/KWH	CONSTANT $ COST/KWH DEFLATED @ 6%	PRESENT VALUE OF COSTS @ 9.18%
1987	43722228	6517	6.71	6.71	43722228
1988	82441429	6517	12.65	11.93	75509642
1989	95852957	6517	14.71	13.09	80411833
1990	117712857	6517	18.06	15.16	90447297
1991	139008571	6517	21.33	16.89	97830734
1992	153347143	6517	23.53	17.58	98847537
1993	165172679	6517	25.34	17.87	97515671
1994	177553479	6517	27.24	18.12	96015155
1995	190875355	6517	29.29	18.37	94537723
1996	205191015	6517	31.49	18.63	93083035
1997	220550344	6517	33.84	18.92	91550725
1998	237123370	6517	36.39	19.17	92242457
1999	254929162	6517	39.11	19.44	88351888
2000	274223272	6517	42.05	19.71	87484665
2001	294572243	6517	45.20	19.99	86133522
2002	316571611	6517	48.59	20.27	84513073
2003	340421992	6517	52.23	20.56	83526214
2004	365933538	6517	56.15	20.85	82222040
2005	393400153	6517	60.36	21.15	80957829
2006	422935164	6517	64.89	21.45	79712105
2007	454622051	6517	69.75	21.75	78450542
2008	486719703	6517	74.69	22.06	77277249
2009	525373764	6517	80.61	22.37	76238742
2010	564776795	6517	86.66	22.69	74317931
2011	607135056	6517	93.16	23.01	73765136
2012	652670185	6517	100.14	23.33	72532280
2013	701620449	6517	107.66	23.66	71511492
2014	754241982	6517	115.73	24.00	70412035
2015	810810131	6517	124.41	24.34	69329635
2016	871622691	6517	133.74	24.65	68261645
TOTAL:	10920252916	AVERAGE:	55.87	19.53	

SUM OF PRESENT VALUE: 2456458611
AMORTIZATION OF PRESENT VALUE @9% 125023.911

LEVELIZED COST OF POWER: 1987 MILLS/KWH 19.19
1982 MILLS/KWH 14.34
1980 MILLS/KWH 12.75

IV
OPERATION AND MAINTENANCE COSTS, TAXES, AND DECOMMISSIONING

Bonneville, Battelle, and AEA have all included estimates of the operation and maintenance and decommissioning costs associated with plant #3. In addition, Battelle and Bonneville have included the property and generation taxes which will be assigned to the units; AEA disregarded these, as they assumed that the tax revenues would be derived from consumers in any event, and therefore were not really a cost of the project output.

The various estimates of operation and maintenance costs are remarkably similar, unlike the capital or fuel cost estimates. Battelle assumes a 1990 O&M cost of $94/kw, or a total of $116.6 million for the entire plant. The May, 1982 Official Statement, used in the Base Case and the Pessimistic Scenario, shows O&M costs (adjusted to 100% of plant from the Supply System 70% share) at $116.5 million for 1990. WPPSS Action Memorandum #24, relied on by Bonneville, shows 1990 O&M costs (adjusted to 100% of plant) at $110.5 million.

Bonneville assumed an escalation rate of only .5%, leading to an overall, levelized $1980 O&M cost of 10.2 mills/kwh. This compares with 11.9 mills for Battelle and 11.8 from the Official Statement, derived using a 1.65% escalation rate, as detailed by Battelle in Appendix A. A small difference between Battelle and the Official Statement is due to different assumptions in the early years of operation, from which later years are escalated. The difference is insignificant; the lower figure from the Battelle, developed in Table IV-1 is used in the base and optimistic cases. In the pessimistic case, post-1990 real escalation of 5% is assumed.

Bonneville has provided no explanation for their use of .5% escalation in O&M costs. AEA assumed escalation in early years at 1.5%, similar to Battelle, decreasing to 0% by the year 2000. Again, no explanation was provided. Historically, O&M costs for nuclear plants have escalated at a rate far above inflation. One study found that nuclear O&M costs has increased nearly 12% above the rate of inflation:

"Data reported to FERC (and its predecessor agency) indicate that O&M costs for nuclear plants have been increasing nearly 12% in real terms annually since 1975. In the past, it had been assumed that O&M costs would remain reasonably stable, and that reactors larger than 800 MWe would experience economies of scale. The FERCdata indicate, however, that O&M costs and manpower levels are continuing to increase for both old plants and the newer larger units. These trends are reflective of several important factors, such as the increase in equipment size, complexity of newer, larger reactors, and the associated reduction of plant availabilities. Increased forced outages are indicative of equipment failures that require expensive replacements and repairs by specialized personnel working in high radiation environments."
(Projected Costs of Electricity from Nuclear and Coal-fired Power Plants, Vol. 1, Page 14; U.S. Department of Energy DOE/EIA-0356/1)

Intuition suggests that O&M costs will escalate much faster than prices generally for any unique piece of equipment. Examples include antique automobiles, obsolete office equipment, and antiquated industrial equipment, all of which require increasing amounts of replacement parts and materials to be fabricated, rather than delivered from inventory, to provide for continued operation.

DECOMMISSIONING COSTS

Estimates of decommissioning costs for nuclear plants range from a nominal sum to an amount equal to the initial construction cost.

Decommissioning reserves must be provided so that when a project is at the end of its operating life, sufficient funds have accrued to pay the costs of entombment, dismantling, or some other means of decommissioning.

In some ways, decommissioning reserves should be provided as an initial capital cost; even if a project operates for only a short period, fuel loading makes the project radioactive, and it must then be decommissioned. WPPSS has opted to provide for decommissioning funds by accruing them through the operating life of the project, imposing a risk on the region by not providing a capitalized decommissioning fund.

AEA assumed a decommissioning cost of $14 million (1982$); this is less than 5% of the decommissioning cost assumed in the Model Plan (page 57). One difference is that AEA applied a 3% real discount rate to decommissioning costs, which were assumed to take place 90 years in the future, while the Model Plan did not discount environmental costs, including decommissioning.

In the May, 1982 Official Statement, an annual decommissioning payment of $1.7 million was included; in Action Memorandum #24, this was raised to $7.8 million. The only difference was a reduction in the anticipated rate of earnings on the reserve fund, from 10% to 9%, coupled with an increase in the rate of escalation in decommissioning costs, from 2% real to 3% real (8% nominal to 9% nominal.) With decommissioning scheduled for the year 2077, escalation rates can make a significant difference.

Bonneville has since requested that WPPSS accrue funds for decommissioning through the assessment of a schedule of charges which is constant in real terms, instead of the constant nominal rate assumed in Memorandum #24 and in the Official Statement. The effect of this is to greatly decrease payments in early years, and to greatly increase payments in later years. Since the overall decommissioning cost is calculated in this analysis in levelized, constant dollars, the method by which costs are paid into the fund should be totally irrelevant, so the change requested by Bonneville will not affect the bottom line of analysis.

The estimate of decommissioning costs used in Action Memorandum #24 has been used in all scenarios for determining decommissioning costs. Since this cost is expressed as an unvarying stream of nominal dollar payments, and tax expenses have also been expressed this way, the two were combined for simplicity of analysis. Both are subject to increases over time; the pessimistic scenario assumes that these costs increase faster than inflation (2% real). These calculations are detailed on table IV-2, and in the three scenarios, Tables VII-1 through VII-3.

TAXES

The items included as taxes in this analysis include only the generation tax to be paid by WPPSS. This is an in-lieu-of tax, subject to change by the Washington legislature, and therefore may not remain as the unvarying stream of nominal dollars expressed by WPPSS in Action Memorandum #24 and the May, 1982 Official Statement. As the two figures are identical, they were used in all analyses; in the base scenario, they are allowed to rise at a rate equal to inflation over the plant lifetime; in the pessimistic scenario, these costs are escalated at 2% above the rate of inflation.

Taxes and decommissioning as detailed on table IV-2, combined add only .7 mills/kwh (levelized 1980$) to the cost of power from the project in the base case. Given experience which will be gained during the plant life with decommissioning costs, and the possibility for increases in the tax rate, this estimate could be subject to large increases. Again, in the pessimistic scenario, 2% real escalation is assumed.

CAPITAL ADDITIONS

Retrofit requirements have been imposed on nuclear plants regularly by the Nuclear Regulatory Commission. WPPSS has budgeted for these in Action Memorandum #24; no allowance is provided in the Official Statement. Battelle assumed a cost for additions from the Nuclear Task Force; BPA has apparently included these as an O&M cost.

The cost provided by WPPSS may be significantly lower than will actually be required. Two recent studies of nuclear backfit, on the systems of Northeast Utilities, Duke Power and Commonwealth Edison, two nuclear-dependent utilities, suggests that over a period often to fifteen years, the backfit costs, in nominal dollars, can equal or exceed the original construction costs (Backfitting and Regulatory Impact Costs, Power Engineering, August, 1983).

This analysis assumes the capital additions shows in Action Memorandum #24, escalated at the 1.65% O&M escalation rate used by Battelle in the base and optimistic scenario. The total of capital additions shown in Table IV-3 is only $2.4 billion, in mixed nominal dollars, or $542 million 1987 dollars. This is a much smaller proportion than noted in the Power Engineering report cited above. This estimate has been used in all three scenarios, although there is a continuing risk of additional costs.

In the Pessimistic analysis, one change was made: the inclusion of a steam generator replacement at mid-life. Numerous nuclear plants have suffered steam generator deterioration, including the Trojan plant in this region. Virginia Electric Power has replaced the steam generators at the Surry 1&2 plants, after less than ten years of service; steam generator replacements have also been initiated at Turkey Point units 3&4 (Florida) and at Point Beach 1 (Wisconsin). The replacement of the steam generator is assumed to cost $200 million in 1983 dollars, escalating at the rate assumed for other O&M costs.

Capital additions add less than 3 mills/kwh to the optimistic and base scenarios; approximately 5 mills/kwh is added for this cost in the pessimistic alternative, due to the allowance of a steam generator replacement at mid-life.

TABLE IV-1

NOMINAL DOLLAR ANALYSIS OF WPPSS #3 O&M COSTS

YEAR	O&M COST $ NOMINAL	OUTPUT MILLION KWH	NOMINAL O&M COST MILLS/KWH	BATTELLE CONSTANT $ COST/KWH DEFLATED @ 6%	PRESENT VALUE OF COSTS @ 9.18%
1987	91779527.56	6517.44	14.08	14.08	91779527.56
1988	99580787.40	6517.44	15.28	14.41	91207902.02
1989	107840944.88	6517.44	16.55	14.73	90468523.92
1990	116550720.00	6517.44	17.88	15.02	89551275.25
1991	125476840.00	6517.44	19.25	15.25	88326203.34
1992	135075918.26	6517.44	20.73	15.49	87068719.45
1993	145409118.36	6517.44	22.31	15.73	85848577.11
1994	156532915.91	6517.44	24.02	15.97	84645533.30
1995	168507683.98	6517.44	25.85	16.22	83459348.41
1996	181396521.80	6517.44	27.83	16.47	82289766.19
1997	195273508.72	6517.44	29.96	16.73	81135613.70
1998	210214385.14	6517.44	32.25	16.99	79995601.25
1999	226295462.65	6517.44	34.72	17.26	78878522.39
2000	243607265.54	6517.44	37.38	17.52	77773153.83
2001	262243226.06	6517.44	40.24	17.80	76683275.41
2002	282304596.02	6517.44	43.32	18.07	75606670.07
2003	303900897.62	6517.44	46.63	18.36	74549123.76
2004	327149316.28	6517.44	50.20	18.64	73504425.47
2005	352176238.98	6517.44	54.04	18.93	72474367.12
2006	379117721.26	6517.44	58.17	19.23	71458743.54
2007	408122226.94	6517.44	62.62	19.53	70457352.47
2008	439341424.30	6517.44	67.41	19.83	69469994.44
2009	472951043.26	6517.44	72.57	20.14	68496472.81
2010	509131758.07	6517.44	78.12	20.45	67536593.68
2011	548080380.62	6517.44	84.09	20.77	66590165.87
2012	590008529.74	6517.44	90.53	21.09	65657000.87
2013	635144182.26	6517.44	97.45	21.42	64736912.84
2014	683732712.21	6517.44	104.91	21.75	63829718.51
2015	736038254.69	6517.44	112.93	22.09	62935237.20
2016	792345191.94	6517.44	121.57	22.44	62053290.76
TOTAL:	9925339310.44	AVERAGE:	50.76	18.08	

1.65% ESCALATION	SUM OF PRESENT VALUE:		2295464532.51
FROM BATTELLE A.1	AMORTIZATION OF PRESENT VALUE @3%		116931849.79
	LEVELIZED COST OF POWER:	1987 MILLS/KWH	17.55
		1982 MILLS/KWH	13.41
		1980 MILLS/KWH	11.94

TABLE IV-2

NOMINAL DOLLAR ANALYSIS OF WPPSS #3 TAXES/DECOM

YEAR	TAXES/DECOM $ NOMINAL	OUTPUT MILLION KWH	NOMINAL O&M COST MILLS/KWH	MEMO 24 CONSTANT $ COST/KWH DEFLATED @ 6%	PRESENT VALUE OF COSTS @ 9.18%
1987	7260000.00	6517.44	1.11	1.11	7260000.00
1988	12521428.57	6517.44	1.92	1.61	11468610.16
1989	12630000.00	6517.44	1.94	1.72	10595395.45
1990	12675714.29	6517.44	1.94	1.63	9739545.99
1991	12675714.29	6517.44	1.94	1.54	8920723.56
1992	12675714.29	6517.44	1.94	1.45	8170657.23
1993	12675714.29	6517.44	1.94	1.37	7483657.47
1994	12675714.29	6517.44	1.94	1.29	6854421.57
1995	12675714.29	6517.44	1.94	1.22	6278092.67
1996	12675714.29	6517.44	1.94	1.15	5750222.26
1997	12675714.29	6517.44	1.94	1.08	5266735.91
1998	12675714.29	6517.44	1.94	1.02	4823901.73
1999	12675714.29	6517.44	1.94	.97	4418301.64
2000	12675714.29	6517.44	1.94	.91	4046824.94
2001	12675714.29	6517.44	1.94	.86	3706544.19
2002	12675714.29	6517.44	1.94	.81	3394893.01
2003	12675714.29	6517.44	1.94	.77	3109445.88
2004	12675714.29	6517.44	1.94	.72	2847999.52
2005	12675714.29	6517.44	1.94	.68	2608535.92
2006	12675714.29	6517.44	1.94	.64	2389206.74
2007	12675714.29	6517.44	1.94	.61	2188319.05
2008	12675714.29	6517.44	1.94	.57	2004322.27
2009	12675714.29	6517.44	1.94	.54	1835795.18
2010	12675714.29	6517.44	1.94	.51	1681439.99
2011	12675714.29	6517.44	1.94	.48	1540062.27
2012	12675714.29	6517.44	1.94	.45	1410571.79
2013	12675714.29	6517.44	1.94	.43	1291969.03
2014	12675714.29	6517.44	1.94	.40	1183339.55
2015	12675714.29	6517.44	1.94	.38	1083841.85
2016	12675714.29	6517.44	1.94	.35	992711.00
TOTAL:	374655714.29	AVERAGE:	1.92	.92	

1.65% ESCALATION
FROM BATTELLE A.1

SUM OF PRESENT VALUE: 134346157.82
AMORTIZATION OF PRESENT VALUE @9% 6838219.94

LEVELIZED COST OF POWER:
1987 MILLS/KWH 1.05
1982 MILLS/KWH .76
1980 MILLS/KWH .70

Table IV-3

NOMINAL DOLLAR ANALYSIS OF WPPSS #3 CAPITAL ADDITIONS

YEAR	CAPITAL ADDS $ NOMINAL	OUTPUT MILLION KWH	NOMINAL O&M COST MILLS/KWH	MEMO 84 CONSTANT $ COST/KWH DEFLATED @ 6%	PRESENT VALUE OF COSTS @ 9.18%
1987	12857142.86	6517.44	1.97	1.97	12857142.86
1988	23602657.14	6517.44	3.63	3.45	21801491.17
1989	25707142.86	6517.44	3.94	3.51	21565902.19
1990	27764285.71	6517.44	4.26	3.58	21333360.42
1991	29983714.29	6517.44	4.60	3.64	21102895.03
1992	32384285.71	6517.44	4.97	3.71	20874634.14
1993	34861683.57	6517.44	5.35	3.77	20562106.29
1994	37528592.35	6517.44	5.75	3.83	20293577.60
1995	40399540.45	6517.44	6.20	3.89	20008291.22
1996	43492105.29	6517.44	6.67	3.95	19722989.91
1997	46817098.34	6517.44	7.18	4.01	19452416.01
1998	50392606.37	6517.44	7.73	4.07	19179020.47
1999	54254099.75	6517.44	8.32	4.14	18911042.99
2000	58404538.39	6517.44	8.95	4.20	18646032.03
2001	62872495.57	6517.44	9.65	4.27	18384734.83
2002	67692230.72	6517.44	10.39	4.33	18127099.32
2003	72859921.37	6517.44	11.18	4.40	17873074.21
2004	78433725.35	6517.44	12.03	4.47	17622603.83
2005	84433833.81	6517.44	12.96	4.54	17375653.48
2006	90893075.92	6517.44	13.95	4.61	17132158.79
2007	97846396.23	6517.44	15.01	4.68	16892076.33
2008	105321645.54	6517.44	16.16	4.75	16655358.28
2009	113385516.43	6517.44	17.40	4.83	16421957.49
2010	122063914.44	6517.44	18.73	4.90	16191827.40
2011	131401696.24	6517.44	20.16	4.98	15964922.40
2012	141453926.00	6517.44	21.70	5.05	15741197.08
2013	152275151.34	6517.44	23.36	5.14	15520606.94
2014	163924200.42	6517.44	25.15	5.22	15303168.05
2015	176464401.75	6517.44	27.08	5.30	15089657.09
2016	189963920.49	6517.44	29.15	5.38	14877211.36
TOTAL:	2369945682.73	AVERAGE:	12.12	4.29	

1.65% ESCALATION	SUM OF PRESENT VALUE:		541510846.56
FROM BATTELLE A.1	AMORTIZATION OF PRESENT VALUE @3%		27562382.09
	LEVELIZED COST OF POWER:	1987 MILLS/KWH	4.23
		1982 MILLS/KWH	3.16
		1980 MILLS/KWH	2.81

V
AVAILABILITY VERSUS CAPACITY FACTOR

In their analysis of WPPSS #3 costs, both Battelle and Bonneville have used an estimate of "equivalent availability" in evaluating the cost of power from WPPSS project #3. In both cases, a figure of 65% was used. The Regional Plan also used this estimate in running the Strategic Analysis Model. Bonneville made their calculations assuming a 65% capacity factor as well; Battelle and the Regional Council assumed that this capacity factor would be reached under critical water conditions, but assumed an average capacity factor of 60% over the project lifetime.

Both "Availability" and "Capacity Factor" are defined in the Glossary of Electric Utility Terms (Edison Electric Institute Publication #70-40, Revised 12/79).

Availability is defined as the percent of time a unit is or is expected to be available for service, whether operated or not. It is equal to the number of hours in which a unit is capable of producing energy divided by the total hours in the period under consideration, expressed as a percentage. In other words, a unit is available if it can be operated at any level of output.

Capacity factor is defined as the ratio of the average load on a generating station for the period of time considered to the capacity rating of the generating station, expressed as a percentage. In other words, it is the actual output divided by the theoretical output of a unit operating at rated capacity every hour of the year.

The differences between the two are important; an estimate of costs based upon availability will be significantly lower than an estimate based upon capacity factor. Capacity factor is the appropriate measure of a baseload plant from the ratepayer's perspective.

Peak load powerplants, such as combustion turbines, can be expected to be available for operation almost 100% of the time. First, they are relatively simple machines, and generally work when needed. Second, they are used very little, due to high running cost per unit of output, and thus can be maintained during the off-peak season, insuring their availability as needed during peak periods. Combustion turbines typically have availability near 100%, and capacity factors of 5% or less.

At the opposite extreme are wind generators, which cannot be reliably depended upon to operate at particular times. However, such units can be expected to reliably produce energy output over the course of a year. With negligible operating costs, wind generators would normally be operated whenever their output is available. Such a unit might have an availability factor very close to its capacity factor, but both may be 35% or less.

Availability

Coal and nuclear baseload power plants are generally expected to have a predictable period of planned shutdown, and an estimable, but unpredictable, period of forced outage each year. In addition, such units are frequently run at less than full capacity when they do operate.

When a unit is entirely shut down, due to maintenance or forced outage, both the availability and capacity factors are affected. However, when a unit is taken out of service for "economy" reasons, or operates at part-load due to either technical or economic reasons, the capacity factor is affected, but the unit is considered to be "available" for service. (In fact, it may be IN SERVICE, but at a portion of rated capacity.)

For nuclear plants, the use of an "availability" factor may seriously overstate the energy anticipated to be available from a unit for two reasons. First, economy shutdowns during periods of plentiful hydropower will cause units to remain idle even when they may be "available." Second, and perhaps more important, such units are frequently operated at far less than rated capacity, so that a unit which is "available" may in fact be capable of producing far less power than the rated capacity.

The Trojan plant, for example, was built as a 1216 MW powerplant (See: Nucleonics Week, November 22, 1979 page 14) but operates at a much lower level. At the time of licensing, it was considered to be an 1130 MW plant (See: Nuclear News, August, 1980 Page 106; Commercial Nuclear Power Plants, Edition No. 14, Page 36, NUS Corporation, January, 1982)

In the 1978 Portland General Electric Annual Report to the Federal Energy Regulatory Commission, it was further derated to 1056 MW, while Bonneville rates the unit at 1080 MW. Clearly it is being run at significantly less than the capacity for which it was designed, but it is still considered "available," even at these lower operating levels, at any time it is capable of generating a single kilowatt of capacity.

Economy shutdowns are relatively common for thermal plants in the Pacific Northwest. According to Bonneville (Power Situation Statement Monthly Summary, 1978-83) both the Centralia coal plant and the Trojan nuclear plant have been out of service for "economy" reasons on several occasions.

Table V-1 shows the monthly and annual capacity factors for each of the major thermal plants in the Bonneville grid for the period 1978-83. As is evident, the plants have failed to operate anywhere near their theoretical capability, even at times when the Northwest-Southwest intertie was less than full. This is due to "economy" operations, to unscheduled and scheduled maintenance, and to gradual ascension to full power after shutdowns. An adjustment has been made to the figures for Trojan, expressing the capacity factor as a percentage of the

TABLE V-1

HISTORICAL CAPACITY FACTORS; BPA THERMAL CAPACITY

YEAR/MONTH	HANFORD	CAP	TROJAN	CAP	CENTRALIA	CAP		INTERTIE
1978								
JANUARY	88.30	852	97.30	1068	79.50	1313		2217
FEBRUARY	60.30	852	83.60	1068	83.40	1313		1728
MARCH	76.60	852	41.90	1068	74.40	1313		1310
APRIL	96.40	852	.00	1068	49.40	1313		2485
MAY	.00		.00		.00		NO DATA	2591
JUNE	.00		.00		.00			2299
JULY	.00		.00		7.20	1313		2142
AUGUST	38.70	852	.00		47.30	1313		755
SEPTEMBER	52.80	852	.00		56.40	1313		1953
OCTOBER	71.90	852	.00		86.00	1313		1048
NOVEMBER	84.20	852	.00		77.60	1313		358
DECEMBER	51.50	852	.00		81.60	1313		-24
	51.73		18.57		53.57			
		ADJ:	17.75					
1979								
JANUARY	83.20	852	88.90	1068	81.10	1313		-180
FEBRUARY	66.20	852	100.30	1080	81.20	1313		14
MARCH	76.10	852	100.90	1068	74.50	1313		1168
APRIL	73.90	852	84.70	1080	83.50	1313		1228
MAY	8.70	852	.00	1080	69.00	1313		2393
JUNE	.00	852	.00	1080	64.00	1313		956
JULY	.00	852	83.10	1080	41.80	1313		348
AUGUST	42.20	840	97.50	1060	42.60	1313		137
SEPTEMBER	80.40	840	66.70	1080	61.80	1313		275
OCTOBER	100.90	840	32.80	1080	41.20	1313		21
NOVEMBER	35.80	840	.00	1080	53.60	1313		119
DECEMBER	26.50	840	.20	1080	85.50	1313		150
	49.49		56.29		64.58			
		ADJ:	53.80					
1980								
JANUARY	91.70	840	92.50	1080	82.30	1313		-177
FEBRUARY	67.20	840	69.60	1080	86.80	1313		-410
MARCH	44.60	840	63.30	1060	81.70	1313		-614
APRIL	92.10	840	21.20	1080	74.50	1313		490
MAY	37.00	840	.00	1060	22.40	1313		2435
JUNE	.00	840	.00	1080	1.50	1313		2768
JULY	.00	840	26.00	1060	30.00	1313		1550
AUGUST	.00	840	92.80	1080	54.80	1313		464
SEPTEMBER	.00	840	98.90	1080	73.40	1313		652
OCTOBER	.00	840	97.60	1080	68.50	1313		437
NOVEMBER	.00	840	98.60	1060	76.60	1313		756
DECEMBER	.00	840	88.10	1080	70.50	1313		1665
	27.70		64.12		62.00			
		ADJ:	61.28					

TABLE V-1

1981								
JANUARY	.00	840	65.00	1080	50.60	1313		2600
FEBRUARY	.00	840	54.70	1080	74.60	1313		2200
MARCH	16.50	840	59.40	1080	79.50	1313		2200
APRIL	54.10	840	93.30	1080	63.00	1313		1800
MAY	5.60	840	2.00	1080	25.70	1313		2600
JUNE	.00	840	.00	1080	2.50	1313		2600
JULY	.00	840	.00	1080	.00	1313	NO DATA	NO DATA
AUGUST	43.10	840	91.30	1080	81.20	1313		2600
SEPTEMBER	100.90	840	56.70	1080	81.20	1313		1800
OCTOBER	13.20	840	69.10	1080	86.90	1313		1600
NOVEMBER	78.50	840	96.60	1080	90.60	1313		1900
DECEMBER	17.90	840	56.60	1080	87.70	1313		2300
	27.87		65.48		60.23			
		ADJ:	62.58					
1982								
JANUARY	71.40	840	73.80	1080	79.80	1313		2500
FEBRUARY	53.90	840	92.10	1080	61.20	1313		2300
MARCH	69.80	840	71.20	1080	25.50	1313		2700
APRIL	53.20	840	.00	1080	24.70	1313		2500
MAY	.00	840	.00	1080	21.90	1313		2600
JUNE	.00	840	.00	1080	.00	1313		2600
JULY	.00	840	.00	1080	.00	1313		2500
AUGUST	73.30	840	15.60	1080	54.10	1313		3000
SEPTEMBER	61.80	840	84.60	1080	73.00	1313		2500
OCTOBER	51.20	840	98.90	1080	72.10	1313		2700
NOVEMBER	66.60	840	78.20	1080	84.00	1313		2600
DECEMBER	85.60	840	99.10	1080	76.00	1313		2500
	49.35		51.13		47.65			
1983								
JANUARY	69.10	840	64.30	1080	64.30	1313		2600
FEBRUARY	55.70	840	.00	1080	53.40	1313		2300
MARCH	39.80	840	.00	1080	26.00	1313		2300
APRIL	84.10	840	.00	1080	29.20	1313		2200
MAY	.00	840	.00	1080	39.10	1313		2200
JUNE	12.80	840	.00	1080	19.60	1313		2400
JULY	55.40	840	12.50	1080	51.60	1313		2700
	45.27		10.97		40.46			

TABLE V-1 --

CAPACITY FACTORS OF MONTANA/WYOMING COAL PLANTS
(30 MW and larger only)

PLANT	1978	1979	1980	1981	1982	1983 (6 MOS)
BRIDGER	55	56	53	51	51	30
COLSTRIP	59	61	49	66	51	32
CORETTE	61	71	66	51	35	14
JOHNSTON	74	79	75	70	71	49
LEWIS/CLARK	73	69	68	46	38	44
OSAGE	91	80	72	70	62	55
WYODAK	(NEW)	75	85	84	82	55

licensed capacity (1130 MW) rather than the current derated capacity. Since ratepayers are paying for a plant they expected to be rated at 1130 MW, this is an expression of "what we got as a percentage of what we paid for," essentially similar to the definition of capacity factor.

Economy shutdowns take two forms: most often, plants are taken out of service when no market is available at a price which covers the variable operating costs of the plant; less often, but of increasing concern in the region, plants may be taken out of service when the power they generate serves to glut the market, and depress the price available for other surplus energy. In 1982 and 1983, Bonneville paid direct compensation to Portland General Electric in order to keep the Trojan plant out of operation.

TABLE V-2

REPORTED ECONOMY SHUTDOWNS OF NW THERMAL PLANTS
[Operation at less than rated capacity w/o a forced outage]

CENTRALIA:	SPRING, 1983
	SPRING, 1982
	SPRING, 1981
	SPRING, 1980
	SPRING, 1979
TROJAN:	WINTER, 1983
	SPRING, 1983
	SPRING, 1980

SOURCE: BPA POWER SITUATION STATEMENTS, 1978-83

Nuclear plants, and to an even greater extent, coal plants, are often operated at less than full power. Nuclear plants cannot be brought into service quickly. Once refueling is completed, the units must be brought up to temperature slowly; the maximum rate of increase is about 1% per hour (Battelle Data Sheets.) This means that four days are required to bring a cold unit up to full power. Coal plants also require a "warm-up" period, but this is measured in hours, rather than days, given a maximum rate of increase of about 15% per hour.

When a nuclear plant is taken out of service for a forced outage, output generally ceases immediately and the plant begins to cool off. When repairs are complete, the cool plant must be warmed back up again slowly, so that full output is again unobtainable for about four days, even though the plant is theoretically "available" during this entire four day period.

In addition, at the end of the operating season, nuclear fuel is partially exhausted, and cannot produce the full amount of heat needed to drive the power generator at full capacity.

(This is intuitive; if the fuel were capable of providing full capacity, it would not yet be necessary to refuel.) During the last four to eight weeks of operation, nuclear plants generally "coast down," in operation. During "coast down," operators systematically implement reductions in plant output to about one-half of rated capacity. While it is possible to "coast down" all the way to zero output, extracting every possible unit of output from the fuel, this is not done due to 1) the relatively low cost of fuel, and 2) the fact that auxiliary plant equipment, such a pumps and steam generators, lose efficiency rapidly as power output decreases.

During both the "warm-up" and "coast down" periods, nuclear units are producing energy, and therefore considered "available" for service. However, they cannot, and do not, produce at full output during these periods.

Assuming a four day warm up period, two forced outages per operating year requiring plant restart, and a coast down period of six weeks to one-half power, the table below shows the relationship between a unit with 65% availability, and the capacity factor to be expected IF THERE IS A NEED FOR ALL ACHIEVABLE OUTPUT.

TABLE V-3

1000 MW NUCLEAR PLANT
65% AVAILABILITY

Theoretical output at 100% Capacity Factor:	8,760,000 MWH
Theoretical output at 65% Availability:	5,694,000 MWH
Warm-up: Three periods per year; each period 4 days; average output 500 MW	
Lost output:	72,000 MWH
Coast-down: 42 days per year; average output 750 MW	
Lost output:	252,000 MWH
NET OUTPUT:	5,370,000 MWH
Net Capacity Factor:	61.3%

The combination of economy shutdowns and partial load operation leads to an expection that nuclear plants in the Northwest will operate at far less than the 65% availability factor which BPA, Battelle, and the Regional Council have assumed. Since the capital costs continue at the same level, however, estimation of the cost per kilowatt-hour must reflect the economic costs

TABLE V-4

NUCLEAR PLANT CAPACITY FACTORS THROUGH 1981
ALL NUCLEAR PLANTS BUILT SINCE 1966
1000 MW AND LARGER

PLANT	OWNER	CAPACITY	YEARS IN OPERATION	LIFETIME POTENTIAL	LIFETIME OUTPUT-GWH
BROWNS FERRY 1	TVA	1065	7	65325.60	30507.60
BROWNS FERRY 2	TVA	1065	6	55976.40	32634.08
BROWNS FERRY 3	TVA	1065	4	37317.60	23492.18
COOK 1	INDIANA/MICHIGAN ELE	1050	6	55186.00	35397.03
COOK 2	INDIANA/MICHIGAN EL	1100	6	57816.00	36023.27
PEACH BOTTOM 2	PHILA ELECTRIC	1065	7	65325.60	40991.14
PEACH BOTTOM 3	PHILA ELECTRIC	1065	7	65325.60	39523.48
SALEM 1	PUB SVC EL & GAS (NJ	1090	4	33193.60	18431.47
TROJAN	PORTLAND GE	1130	6	59392.80	26202.52
ZION 1	COMM EDISON	1040	6	72583.20	42751.10
ZION 2	COMM EDISON	1040	7	63772.80	37385.53
TOTALS:		11775		636457.80	367313.39

NATIONAL LIFETIME WEIGHTED AVERAGE CAPACITY 57.71

CAPACITY FACTORS OF LARGE PLANTS IN HYDRO-THERMAL SYSTEMS

BROWNS FERRY 1	TVA	1065	7	65325.60	30507.60
BROWNS FERRY 2	TVA	1065	6	55976.40	32834.03
BROWNS FERRY 3	TVA	1065	4	37317.60	23492.18
RANCHO SECO	SACRAMENTO MUD	916	6	48144.96	25897.66
TROJAN	PORTLAND GE	1130	6	59392.80	26202.52
	TOTALS:			266137.56	140734.03

VI

SURPLUS POWER SUPPLY IMPACT ON #3 POWER COST

If resources are planned to meet power needs in average or drier than average years, the region will have a substantial surplus during wetter than average years. Given the Northwest's tradition of building in-region baseload resources to meet loads under critical water conditions, the surplus is often so large that export of WNP-generated power cannot take place, or the power may be used not for high-cost export, but for lower-value thermal displacement. In some situations, the surplus may be so large that plant operation must be curtailed.

The various studies by Battelle, AEA, and BPA have not appeared to explicitly take into account the fact that the region values a surplus during wet periods at a lower level than under conditions when a surplus can be exported at premium prices. Instead, these studies have included their analysis of surplus power sales in the Systems Analysis Model (SAM), which computes a system present value for each chosen resource package.

The problem with the SAM methodology is that the costs associated with building a resource before it is needed at high cost, and selling a portion of the output as surplus, are not internalized. For example, if a resource has fully distributed costs of $500 million per year, but the output can be sold as surplus for only $100 million per year, the region's ratepayers must provide $400 million per year in subsidies which would not be required if a "schedulable" resource were constructed.

If the surplus is a period of several years, the loss to ratepayers may be very high. For example, a ten year surplus under the above example, would have regional ratepayers paying $4 billion for energy used elsewhere. This "loss" during the surplus period should be internalized in making a computation of the cost of the energy from a particular resource. It may be advantageous to choose a higher cost resource, with better scheduling capabilities. In fact, the SAM may not even have available to it resources which would be preferable, simply because they have been rejected as "too expensive," when the costs to regional ratepayers might actually be lower.

The problem of surplus power is brought about in two ways. First, regional energy planners have seriously overstated the region's power needs in the past, and as a result, the region has power generating capability far in excess of our needs. This surplus, based on the "dry year" capability of the region's hydro system plus available thermal resources, is called the "firm surplus."

In addition, the region typically has far more hydropower available than in the "critical" period which planners have typically used for analysis. On average, this "non-firm" surplus equals about 4300 average MW; the distribution of this surplus varies widely however, and is largely unpredictable.

Table VI-1 details the expected surplus (above firm) generating capability of the hydro system, based upon runs carried out by the Army Corps of Engineers, as reproduced in the 1983 PNUCC forecast (Table IV-15). Modifications may be made in the future to this projected hydro regulation to provide for fishery protection, enhancement, and mitigation.

As noted at the bottom of this table, the 102 year average is 540 MW higher than the 40 year average. This tells us that the 40 years of precise monthly data in this analysis are drier than the actual anticipated average of months during the potential operating lifetime of WNP-3. Monthly data is not available for the early portion of the 102 years of Columbia River hydro data. The most recent 15 years of data, while available, has not been incorporated by PNUCC. As a result, this table conservatively estimates the surplus generation which can be expected to be available if resources are constructed to meet critical water conditions.

The 40 year water analysis is broken into 560 periods, comprising 480 months of data. The months of April and August, the beginning and end of the runoff period, respectively, have been divided into two periods each.

We can assume that regional electric utilities will use "economic dispatch" in determining which resources will be operated to meet load. This means that when available generating resources exceed loads, that the thermal plants with the highest O&M and fuel costs will be the first to be taken off-line. While there are some violations of this, generally utilities follow the economic dispatch rule.

Given fuel costs, which vary to some extent with output, it is likely that WPPSS #3 will not be operated in the wettest periods shown on Table VI-1. The Council has erroneously assumed that all fuel costs are fixed, except for the fuel disposal fee, and therefore assumed that nuclear plants have lower incremental operating costs than any other resource. Only 1.4 mills/kwh is assumed to be variable. Typical hydro projects have O&M costs of 1.5-3.0 mills/kwh (Page 432, FERC Form 1, PGE, PSPL, WWP, 1978-83).

The result of this misanalysis is that the Power Council's SAM operates nuclear plants even during times of spill water conditions; such an analysis is counterintuitive, and illogical. In the 1983 BPA rate proceeding, an "Energy Broker" rate of 3 mills/kwh was proposed, with the expectation that this rate would provide the needed incentive for operators of nuclear plants to take them off line, and substitute surplus hydro instead.

Project #3, if completed on the present schedule, will exacerbate a temporary regional surplus. Even with load/resource balance, the region has resources in excess of the intertie capability in almost one half of the months of the

AVAILABLE

TABLE VI-1

NORTHWEST REGIONAL AREA
SURPLUS ENERGY IN EXCESS OF FIRM LOAD CARRYING CAPABILITY
1998-99 OPERATING YEAR

ENERGY IN AVERAGE MEGAWATTS

WATER CONDITION	JUL	AUG 1-15	AUG 16-30	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-15	APR 16-30	MAY	JUN	ANNUAL AVERAGE
1928-29	6787	5551	551	0	0	0	0	0	0	0	0	0	5169	53	1270
1929-30	0	0	0	0	0	0	0	0	0	0	0	0	4414	0	375
1930-31	0	0	0	0	0	0	0	0	0	0	0	0	3379	0	287
1931-32	0	0	0	0	0	0	0	0	0	0	5508	6374	9029	4926	1668
1932-33	1921	3328	1739	0	0	1639	2272	8055	3894	2842	1720	2732	6872	14388	3459
1933-34	6845	7551	3606	1774	3270	5438	9767	12891	10262	8409	9456	9948	9126	2837	7807
1934-35	0	0	0	0	0	1053	1553	5197	4476	832	0	0	5074	5545	1961
1935-36	5595	5474	213	0	0	0	0	2763	0	1212	0	7090	9682	2526	2168
1936-37	597	2230	0	0	0	0	0	0	0	102	0	0	5162	233	[illegible]
1937-38	0	0	0	0	0	0	0	6552	3685	4617	1041	8777	10405	6173	3026
1938-39	2111	1381	0	0	0	0	0	129	0	0	525	5358	9030	2315	1446
1939-40	3626	3199	0	0	0	0	566	316	865	2581	4195	3877	5522	1565	1696
1940-41	589	1588	0	0	418	565	1354	0	0	212	0	0	3969	0	642
1941-42	0	0	0	0	882	1637	6218	4476	2686	1050	1865	3257	4531	4418	2368
1942-43	4038	4785	856	0	0	567	2268	6884	7389	6076	8568	11304	8885	9328	4745
1943-44	9309	7131	825	0	0	0	0	0	0	0	0	0	3758	0	1439
1944-45	0	0	0	0	0	0	0	0	0	0	0	0	4507	3955	788
1945-46	64	0	0	0	0	0	0	7792	5378	5435	5203	8548	13088	4303	3588
1946-47	2608	3654	612	718	150	2926	7007	8524	9025	6129	3604	4555	11592	2660	4781
1947-48	2225	2959	0	368	5735	5203	4359	9345	7942	4155	2499	6279	14241	15894	6232
1948-49	880	4307	3725	1440	811	2102	1204	2233	5774	6474	4883	7526	13688	2250	3878
1949-50	154	0	0	0	0	900	2399	7649	8087	8715	7465	6103	7877	14372	4788
1950-51	9041	7288	3580	1178	3614	6355	7807	14687	12286	8368	8901	7886	13549	6395	7718
1951-52	4488	6393	944	1248	4428	3555	4357	7165	7246	5075	6669	11337	13561	2571	5499
1952-53	2507	4602	0	0	0	0	0	8278	8223	3760	0	866	6480	11822	3606
1953-54	5173	5360	1953	522	678	2853	3723	8464	9330	5598	5054	3531	11868	10555	5532
1954-55	9920	9953	7051	4316	1319	4204	2704	6743	4666	271	0	0	4442	11024	4848
1955-56	8160	7288	910	390	2533	5226	7575	10834	7864	9386	8266	13087	15118	13414	7930
1956-57	2993	4295	2258	839	1737	2421	4101	6633	6665	6281	5955	3551	14767	6399	5878
1957-58	0	0	0	0	0	0	1367	6892	9569	4541	3765	5393	13357	5822	3785
1958-59	0	0	0	0	78	4234	5658	10731	8083	5024	6327	4237	9656	11873	5821
1959-60	4251	5395	1599	6037	7718	6703	5144	6854	6737	6536	9488	2795	6037	7833	6039
1960-61	4280	5231	0	655	74	2811	1891	8053	13717	7043	4360	0	10978	12371	5263
1961-62	0	0	292	0	0	0	159	6331	5807	3111	3429	5986	6289	6139	2697
1962-63	2377	5233	1412	0	1451	4579	5435	6430	9523	3049	843	0	4925	3179	3698
1963-64	4161	3972	596	955	0	2011	1290	7393	4800	2216	4214	832	6748	14558	4857
1964-65	6102	6355	1969	2114	2341	2903	7838	11262	11274	7252	5200	10258	10411	9789	6984
1965-66	4255	7225	3722	1427	1157	3125	2240	7251	4787	3033	2588	978	5283	4376	3688
1966-67	5084	4616	0	0	0	0	3551	9236	8443	4367	2524	0	7617	14549	4656
1967-68	3643	4651	1226	515	1619	3069	2537	[illegible]	9408	6370	707	0	3542	6284	3998
132YR. AVERAGE	3367	3963	1173	995	1719	2451	3129	6238	5867	4481	4832	4942	8849	7868	4256
40YR. AVERAGE 1928-68	3495	3525	891	612	1831	1902	2627	5750	5372	3751	3348	4043	8284	6379	3716

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water study. Eliminating the months of April through June from analysis, assuming that thermal plants will be out of service for scheduled maintenance anyway, a total of 400 periods incorporating 360 months of data remain in the 40 year study. Table VI-2 shows the distribution of the anticipated surplus hydro capability during these 400 periods.

Assuming load/resource balance, the region has a surplus in excess of the intertie capacity in 110 of the 400 periods, or about 27% of the time. Given a 1000 MW firm surplus (whether a market is available outside the region or not) the total regional surplus exceeds the intertie capability in 140 of the 400 time periods, or 35% of the time.

TABLE VI-2

SUMMARY DATA
SURPLUS ENERGY IN EXCESS OF FIRM LOAD CARRYING CAPABILITY FROM TABLE IV-15; 1983 PNUCC NORTHWEST REGIONAL FORECAST MONTHS OF JULY-MARCH ONLY

SURPLUS MW-MO	NUMBER OF PERIODS			
0	140			
0-1000	40			
1000-2000	30			
2000-3000	31			
		Subtotal:	241	60%
LIMIT OF INTERTIE CAPACITY W/1500 MW FIRM SURPLUS				
3000-4000	23			
4000-4500	19			
		Subtotal:	283	71%
LIMIT OF INTERTIE CAPACITY				
4500-5000	10			
5000-6000	25			
6000-7000	24			
7000-8000	22			
8000-9000	14			
9000-10000	13			
10000-11000	5			
11000+	4			
		Total:	400	100%

NOTE: The month of August is divided into two periods by PNUCC; therefore, all observations are either for a full month, or for half of August; the overall August surplus equals 2600 MW for the 40 years, significantly less than the overall average, so the inclusion of August data in the manner presented by PNUCC tends to skew the above data downward, increasing the conservatism of this analysis.

If the 40 year data is adjusted by the average difference between the 40 year average and the 102 year average, 540 MW, we would anticipate a regional surplus in excess of the intertie capability would increase to 130 of the 400 periods under load/resource balance, and to 180 of the 400 periods given a 1500 MW firm surplus.

The larger average hydro capability in the 102 year study is approximately equal to the additions to the regional intertie planned between 1983 and 1987, the anticipated date of commercial operation of WPPSS #3. Therefore, the use of the present intertie capability, together with unadjusted 40 year data is a reasonable approximation of the amount of time the regional surplus will exceed the intertie capability in the post-1987 period.

In these 120-180 periods, when surplus generation exceeds the intertie capability , the value of incremental energy is very limited. The only "economical use" for energy in excess of the amount which can be exported over the intertie is to displace other thermal generation.

In these periods it will be necessary to curtail output from thermal generating plants. Therefore, the value of the output from WNP #3, as an incremental resource, is only the displaced running cost of a coal plant, assuming that coal is more expensive than nuclear fuel, in many months.

The region has the following coal plants now operating, and subject to curtailment during the period prior to 1994:

TABLE VI-3

Project	Capacity MW	Capability @ 65%; Av MW	Fuel Cost 1982 mills/kwh
Boardman	500	325	18
Bridger	2000	1300	9
Centralia	1300	845	11
Colstrip 1/2	330	215	4
Colstrip 3/4	700	455	9
Valmy	125	81	13
Total:	4955	3221	

Sources: BPA Alumax Rate Impact Study, table 13; Puget Power submittal (B-4), Washington UTC, Cause U-78-05)

This suggests that in any month in which the region has more than 4400 MW of surplus (the intertie capacity), compared with critical generation, the value of that surplus is only 18 mills/kwh for the first 325 MW, displacing Boardman; The next 926 MW of surplus could displace Centralia and Valmy, at an incremental savings of 11-13 mills; any additional surplus in any month has a value of 10 mills/kwh or less, or less than the fuel and O&M cost of WNP 3, even using Bonneville's optimistic estimated fuel and O&M cost.

When a coal plant cannot be displaced, or where coal is less expensive than nuclear running costs, WNP #3 will be shut down instead. In addition, since the investor-owned utilities control the region's coal-fired plants, while Bonneville controls most of the hydro, and the WPPSS projects, the surplus actually accrues to the entity (Bonneville) which is limited in its ability to curtail thermal output. Only the WPPSS projects appear to be available to BPA for curtailment.

Under the "Exportable agreement" between the region's utilities, each utility with energy in excess of their own system needs is entitled to a share of the intertie capability proportional to their share of the total regional surplus. Thus, even if a nuclear unit had lower operating costs than a coal plant, the utilities owning the coal units would have rights to a share of the intertie, displacing sales made by Bonneville.

This suggests that WPPSS 2&3 will be likely candidates for economy shutdowns. The experience in 1983, where private utilities continued to operate thermal plants, including Centralia, Colstrip, and Bridger, when Bonneville was in a spill situation (June, 1983) demonstrates that BPA bears the burden of a hydro surplus.

In any extended period with a surplus exceeding about 5000 MW, WPPSS #3 would likely be shut down for economy reasons, or operated only to displace coal plants with fuel costs of 10 mills/kwh. With fuel costs of 13-20 mills based upon the Base Case fuel cost estimates, an economy shutdown would be the expected outcome.

In March of 1982, BPA paid several million dollars to Portland General Electric to shut down the Trojan plant, in order to "firm up" the market for surplus power, which was glutted at that time, so there is clear precedent for "economy shutdowns" of nuclear plants in the Northwest, even under less than extreme wet conditions. This adjustment means that #3 would not be operated approximately 25% of the time it is scheduled to be available due to a regional surplus of energy costing less than the fuel costs of #3 under critical period load/resource balance . Given a 1500 MW firm surplus, WNP-3 would be shut down about 33% of the time.

Therefore, assuming as a minimum that WNP-3 will not be operated at all in about 100 periods (about 90 months) of the 360 months in which availability would be scheduled, greatly reduces the anticipated capacity factor of the plant. With a firm surplus, this estimate increases, but the point is conservatively illustrated using the figure under load/resource balance.

Assuming that the plant could operate with 65% availability, and therefore a 61.3% capacity factor (as detailed in the section on Availability), during 270 of the 360 months of scheduled availability, and did not operate in the remaining 90 periods, due to availability of less expensive power, the weighted capacity factor would be 46%; this, in fact, is very close to the historical capacity factor of the Trojan plant, of 47.%. (The capacity factor for Trojan is correctly calculated by using the 1130 rated net capacity, rather than the present capacity of 1056 MW (Bonneville rates Trojan at 1080; PGE reports the capacity as 1056 MW); derating has been necessary as corrosion has forced removal hundreds of steam generator tubes from operation; the gross rating of the Trojan reactor itself is 1216 MW.)

If the region implements large amounts of cogeneration, the region will have additional generation with variable operating costs higher than WNP-3. Even with a 5000 BTU incremental heat rate, a gas-fired cogeneration facility would have higher fuel costs than WNP-3, and the region might well choose to operate #3, and leave the cogeneration unused. The resource implementation tables X-4 through X-6 in this analysis do not plan on any cogeneration becoming available until 1992-93 in the high growth forecast, thereby reducing the probability of "glutting the market" during the period when a WPPSS #3 deferral is being considered.

Recognizing that present surplus circumstances may well change over time, particularly if hydro-firming strategies are used in the event of high or medium-high load growth, a 60% capacity factor has been used in the optimistic and base cases for WPPSS #3, and a 50% capacity factor is assumed in the pessimistic case, rather than the 46% developed in the above analysis.

VII
SUMMARY OF CCST TO COMPLETE AND OPERATE SCENARIOS

Tables VII-1 through VII-3 detail the various costs to complete WPPSS #3 as developed in the preceeding sections. The analyses consist of three distinct scenarios, forming a reasonable range of estimates for the cost of power from completion and operation of WPPSS #3, assuming a July, 1984 restart.

Table VII-1 represents the Base Case. In this analysis, the cost to complete the project is taken from Table II-2, assuming a $400 million increase over the August 10, 1983 cost estimate for completing the plant. Fuel costs are taken from table III-3, based upon the figures released by WPPSS in the May, 1982 Official Statement for the first six years of operation, and then escalated at 1.65% thereafter. O&M costs are taken from Table IV-1, based upon Battelle's analysis. Capital replacements (backfits), taxes, and decommissioning are taken from Tables IV-2 and IV-3, and are derived from WPPSS Action Memorandum 24, except that taxes and decommissioning costs are assumed to increase with inflation at 6% (0% real).

The "total" shown is the sum of the nominal costs to ratepayers for all of the direct construction and operating costs for the projects; no environmental, transmission, or distribution costs are included.

The second page of Table VII-1 identifies the annual output of the project, at an assumed 60% capacity factor, and computes the nominal cost to complete and operate on a per-kwh basis, beginning at 117 mills/kwh; this, in fact, represents an average of the public utility and private utility portions, which if computed individually would be lower and higher than the average respectively.

The value of surplus energy is identified from the 1983 BPA Load Forecast Supply Pricing Model (July, 1983); the average figures are used, which will tend to overstate the value of incremental surplus. While a value of surplus is shown for the entire 30 year period, it is not assumed that any surplus will extend beyond a ten year period. The total dollar value of the incremental surplus, together with the loss to ratepayers (difference between total cost and revenue from surplus sales) identifies the amount of money regional ratepayers will spend to support WPPSS #3 if it is brought on line before needed, with the power exported. Approximately 70% of this represents the added net revenue requirement Bonneville must recover from regional ratepayers for power actually used in this region.

The accumulated loss, and present value of the accumulated loss, assuming a 3% real discount rate, represent the amount which WPPSS #3 must recover during the period of operation when the output is useful to the region. A conversion to 1980 $ allows a comparison of the cost of early completion with the estimated cost of delaying construction.

Summary of Scenarios

The final column is a present value of the total project capital and operating costs; the sum of the present values is levelized at 3%, to 95 mills/kwh (1989$) and then deflated to 56 mills/kwh (1980$). This represents the incremental cost of the direct costs of completion and operation of WPPSS #3, expressed in 1980 levelized mills/kwh. The expected value of the loss due to early completion, as shown in Table XI-2 must be added to these to internalize to the busbar cost of power the losses ratepayers will bear during a surplus period, to insure that alternate resources with competitive costs are considered as substitutes. This process is dealt with separately in section XI of this analysis.

This process is repeated for the remaining scenarios. Table VII-2 is the optimistic scenario, and table VII-3 is the pessimistic. The first year nominal costs are 101 mills/kwh and 141 mills/kwh respectively. The levelized, 1980$ busbar costs for the other scenarios are 45 mills/kwh in the optimistic scenario, and 74 mills/kwh in the pessimistic scenario. Again, the loss due to early completion must be internalized to compare completion with alternative, schedulable resources.

TABLE VII-1

TOTAL COSTS OF WPPSS #3 BASE CASE SCENARIO

YEAR	CAPITAL	FUEL	O&M	BACKFITS	TAXES/DECOM	TOTAL
SOURCE:	CASE 2 + .1514 AN CH	OFFICIAL STATEMENT	BATTELLE	MEMO 24	MEMO 24	
ESCAL RATE:		1.5%	1.65%	1.65%	6% NOMINAL	
1989	597424400	43780000	91779528	23857143	7260000	764101071
1990	597424400	82441429	99580787	23302857	12521428	815770901
1991	597424400	95952857	107840944	25707143	12630000	839555344
1992	597424400	117712857	116560000	27764286	12675714	872137257
1993	597424400	138998571	125476840	29985714	13436257	905321782
1994	597424400	153647143	135075818	32384285	14242432	932774078
1995	597424400	165170679	145409118	34861684	15096978	957962859
1996	597424400	177558479	156532916	37528602	16002797	985047194
1997	597424400	190875365	168507684	40399540	16962965	1014169954
1998	597424400	205191017	181398522	43490105	17980743	1045484787
1999	597424400	220580344	195275509	46817098	19059587	1079156937
2000	597424400	237123869	210214085	50398606	20203162	1115364123
2001	597424400	254908160	226295463	54254099	21415352	1154297474
2002	597424400	274026272	243607066	58404538	22700273	1196162548
2003	597424400	294578242	262243006	62872465	24062290	1241180423
2004	597424400	316671610	282304596	67682230	25506027	1289588863
2005	597424400	340421981	303900898	72859921	27036389	1341643588
2006	597424400	365953629	327149316	78433704	28658572	1397619622
2007	597424400	393400152	352176239	84433883	30378086	1457812760
2008	597424400	422905163	379117721	90893075	32200771	1522541131
2009	597424400	454623050	408120227	97846395	34132818	1592146890
2010	597424400	488719779	439341425	105331644	36180787	1666998035
2011	597424400	525373762	472951044	113389515	38351634	1747490355
2012	597424400	564776794	509131798	122063813	40652732	1834049538
2013	597424400	607135054	548080381	131401695	43091896	1927133426
2014	597424400	652670183	590008530	141453924	45677410	2027234447
2015	597424400	701620447	635144183	152275150	48418054	2134882233
2016	597424400	754241980	683732713	163924199	51323138	2250646429
2017	597424400	810810129	736038265	176464400	54402526	2375139720
2018	597424400	871620889	792345192	189963926	57666677	2509021085

TABLE VII-1

OUTPUT KWH	MILLS/KWH NOMINAL	VALUE OF INCREMENTAL SURPLUS BPA RATE FORECAST	VALUE OF INCREMENTAL SURPLUS (NOMINAL $)	LOSS TO RATEPAYERS	ACCUMULATED LOSS	PV OF ACCUM LOSS/9.18% (1989 $)	1980 $	PV OF TOTAL COST @ 3% REAL 1989 $
6517000	117	20	132946800	631154271		631154271	373579243	764101071
6517000	125	23	147935900	667835001	1298989272	1242836815	735633201	747179796
6517000	129	25	162273300	677282044	1976271316	1811013465	1071936087	704308858
6517000	134	27	176610700	695526557	2671797873	2345435611	1388259734	670124613
6517000	139	30	192903200	712418582	3384216455	2846810846	1685022965	637133748
6517000	143	32	210499100	722274978	4106491433	3312383132	1960594486	601258209
6517000	147	35	227443300	730519559	4837010992	3743677025	2215876678	565574906
6517000	151	38	247646000	737401194	5574412186	4142428412	2451897011	532666529
6517000	156	41	269152100	745017854	6319430040	4511424668	2670305329	502303287
6517000	160	45	291309900	754174887	7073604926	4884956267	2891398108	474274645
6517000	166	48	314771100	764385837	7837990764	5231712936	3096642848	448387717
6517000	171	52					0	424465777
6517000	177	57					0	402346905
6517000	184	59					0	381882741
6517000	190	60					0	362937344
6517000	198	65					0	345386155
6517000	206	71					0	329115033
6517000	214	76					0	314019386
6517000	224	82					0	300003366
6517000	234	89					0	286979136
6517000	244	96					0	274856197
6517000	256	104					0	263590770
6517000	268	112					0	253085234
6517000	281	121					0	243287610
6517000	296	131					0	234141084
6517000	311	141					0	225593576
6517000	328	152					0	217597341
6517000	345	164					0	210108607
6517000	364	178					0	203087243
6517000	385	192					0	196495447
								12116303331
								616719840
						LEVELIZED 1989$		95
						LEVELIZED 1980$:		56

Table VII-2

TOTAL COSTS OF WPPSS #3 OPTIMISTIC SCENARIOS

YEAR	CAPITAL	FUEL	O&M	BACKFITS	TAXES/DECOM	TOTAL	OUTPUT MWH
SOURCE	CASE2 .1514 AN CH	WPPSS MEMO #24	BATTELLE	MEMO 24	MEMO 24		
ESCAL RATE:		1.5%	1.65%	1.65%	0%		
1989	483874400	52082857	91779528	23857143	7260000	658853928	6517000
1990	483874400	63540000	99580787	23802857	12521428	683319472	6517000
1991	483874400	67944285	107840944	25707143	12630000	697996772	6517000
1992	483874400	71832857	116560000	27764286	12675714	712707257	6517000
1993	483874400	79335714	125476840	29985714	12675714	731348382	6517000
1994	483874400	86032857	135075818	32384285	12675714	750043074	6517000
1995	483874400	92485321	145409118	34861684	12675714	769306237	6517000
1996	483874400	99421720	156532916	37528602	12675714	790033352	6517000
1997	483874400	106878349	168507684	40399540	12675714	812335687	6517000
1998	483874400	114894225	181398522	43490105	12675714	836332966	6517000
1999	483874400	123511292	195275509	46817098	12675714	862154013	6517000
2000	483874400	132774639	210214085	50398606	12675714	889937444	6517000
2001	483874400	142732737	226295463	54254099	12675714	919832413	6517000
2002	483874400	153437692	243607066	58404538	12675714	951999410	6517000
2003	483874400	164945519	262243006	62872485	12675714	986611124	6517000
2004	483874400	177316433	282304596	67682230	12675714	1023853373	6517000
2005	483874400	190615165	303900898	72859921	12675714	1063926098	6517000
2006	483874400	204911303	327149316	78433704	12675714	1107044438	6517000
2007	483874400	220279651	352176239	84433883	12675714	1153439887	6517000
2008	483874400	236800624	379117721	90893075	12675714	1203361535	6517000
2009	483874400	254560671	408120227	97846395	12675714	1257077408	6517000
2010	483874400	273652722	439341425	105331644	12675714	1314875904	6517000
2011	483874400	294176676	472951044	113389515	12675714	1377067348	6517000
2012	483874400	316239926	509131798	122063813	12675714	1443985652	6517000
2013	483874400	339957921	548080381	131401695	12675714	1515990111	6517000
2014	483874400	365454765	590008530	141453924	12675714	1593467333	6517000
2015	483874400	392863872	635144183	152275150	12675714	1676833319	6517000
2016	483874400	422328663	683732713	163924199	12675714	1766535683	6517000
2017	483874400	454003312	736038265	176464400	12675714	1863056091	6517000
2018	483874400	488053561	792345192	189963926	12675714	1966912794	6517000

539

Table VII-2

MILLS/KWH NOMINAL	VALUE OF INCREMENTAL SURPLUS BPA RATE FORECAST	VALUE OF INCREMENTAL SURPLUS (NOMINAL $)	LOSS TO RATEPAYERS	ACCUMULATED LOSS	PV OF ACCUM LOSS/9.18% (1989$)	PV OF TOTAL COST @ 3% DISCOUNT (1989$)
101	20	132946800	525907128		525907128	658853928
105	23	147935900	535383572	1061290700	1016274935	625865060
107	25	162273300	535723472	1597014172	1465697108	585554380
109	27	176610700	536096557	2133110729	1877617932	547623291
112	30	192903200	538445182	2671555911	2256556785	514697365
115	32	210499100	539543974	3211099885	2604342225	483471363
119	35	227443300	541862937	3752962822	2924254502	454193290
121	38	247646000	542387352	4295350174	3217551706	427212347
125	41	269152100	543183587	4838533761	3486582454	402337778
128	45	291309900	545023066	5383556827	3756524268	379394828
132	48	314771100	547382913	5930939740	4004839538	358223402
137	52					338676833
141	57					320620753
146	59					303932057
151	60					288497961
157	65					274215131
163	71					260988891
170	76					248732494
177	82					237366456
185	89					226817947
193	96					217020231
202	104					207912154
211	112					199437674
222	121					191545436
233	131					184188372
245	141					177323345
257	152					170910819
271	164					164914555
286	178					159301333
302	192					154040704
						9763870180
						496980992
				LEVELIZED 1989$:		76
				LEVELIZED 1980$:		45

Table VII-3

TOTAL COSTS OF WPPSS #3 PESSIMISTIC SCENARIO

YEAR	CAPITAL	FUEL	O&M	BACKFITS	TAXES/DECOM	TOTAL	OUTPUT MWH
SOURCE:	CASE 2 + .1514 AN CH	OFFICIAL STATEMENT	BATTELLE	MEMO 24 +SG @ 15 YRS	MEMO 24		
ESCAL RATE:		1.5%	5% POST-90	1.65%	2% REAL		50% CAP FACT
1989	597424400	43780000	91779528	23857143	7260000	764101071	5431200
1990	597424400	82441429	99580787	23802857	12521428	815770901	5431200
1991	597424400	95952857	107840944	25707143	12630000	839555344	5431200
1992	597424400	117712857	116560000	27764286	12675714	872137257	5431200
1993	597424400	138998571	129381600	29985714	13689771	909480056	5431200
1994	597424400	153647143	143613576	32384285	14784953	941854357	5431200
1995	597424400	165170879	159411069	34851684	15967749	972835531	5431200
1996	597424400	177558479	176946287	37528602	17245169	1006702937	5431200
1997	597424400	190075365	196410379	40399540	18624782	1043734465	5431200
1998	597424400	205191017	218015520	43490105	20114765	1084235807	5431200
1999	597424400	220580344	241997227	46817098	21723946	1128543015	5431200
2000	597424400	237123869	268616922	50398606	23461862	1177025660	5431200
2001	597424400	254908160	298164784	54254099	25338811	1230090254	5431200
2002	597424400	274026272	330962910	58404538	27365916	1288184035	5431200
2003	597424400	294578242	367368830	940426185	29555189	2229352847	5431200
2004	597424400	316671610	407779402	67682230	31919604	1421477246	5431200
2005	597424400	340421931	452635136	72859921	34473173	1497814610	5431200
2006	597424400	365953629	502425001	78433706	37231026	1581467761	5431200
2007	597424400	393400152	557691751	84433883	40209508	1673159694	5431200
2008	597424400	422905163	619037843	90893075	43426269	1773686750	5431200
2009	597424400	454623050	687132006	97846395	46900371	1883926222	5431200
2010	597424400	488719779	762716527	105331644	50652400	2004844750	5431200
2011	597424400	525373762	846615345	113389515	54704592	2137507615	5431200
2012	597424400	564776794	939743033	122063313	59080960	2283089000	5431200
2013	597424400	607135054	1043114766	131401695	63807436	2442883352	5431200
2014	597424400	652670183	1157857391	141453925	68912031	2618317930	5431200
2015	597424400	701620447	1285221703	152275150	74424994	2810966694	5431200
2016	597424400	754241980	1426596091	163924199	80378993	3022565663	5431200
2017	597424400	810810129	1583521661	176464400	86809313	3255029903	5431200
2018	597424400	871620889	1757709044	189963926	93754058	3510472317	5431200

Table VII-3

MILLS/KWH NOMINAL	VALUE OF INCREMENTAL SURPLUS BPA RATE FORECAST	VALUE OF INCREMENTAL SURPLUS (NOMINAL $)	LOSS TO RATEPAYERS	ACCUMULATED LOSS	PV OF ACCUM LOSS/9.18% (1989$)	1980 $	PV OF TOTAL COST @ 3% REAL DISC. (1989$)
141	20	110796480	653304591		653304591	386689984	764101071
150	23	123288240	692482561	1345787252	1287562386	762106198	747179796
155	25	135236880	704318464	2050105716	1878420079	1111833958	704308858
161	27	147135520	724951737	2775057453	2435451668	1441540100	670124613
167	30	160763520	748716536	3523773989	2962372131	1753423512	640060196
173	32	175427760	766426597	4290200586	3456404174	2045840319	607111279
179	35	189548880	783286701	5073487287	3918851436	2319562143	574355662
185	38	206385600	800317337	5873804624	4351624872	2575720075	544376922
192	41	224308560	819425906	6693230530	4757474330	2815941745	516946150
200	45	242774640	841461167	7534691698	5174237525	3062623240	491853693
208	48	262326960	866216055	8400907753	5567188544	3295210344	468907541
217	52						447931847
225	57						428765564
237	59						411261204
410	60						651891850
262	65						380709367
276	71						367424932
291	76						355326676
308	82						344319623
327	89						334316809
347	96						325238606
369	104						317012114
394	112						309570587
420	121						302852925
450	131						296803194
482	141						291370199
518	152						286507081
557	164						282170960
599	178						278322594
646	192						274926082

SUM OF PV: 13416047994
AMORT OF PV: 682876843
MILLS/KWH: 126
1980 $: 74

VIII

COSTS TO COMPLETE WPPSS #1

This analysis does not deal with the costs to complete and operate WPPSS #1 in detail. The most recent complete construction budget for WPPSS #1 is now two years out of date; to attempt to analyze this in detail would be illogical.

WPPSS #1 is expected to be somewhat more expensive to complete and operate than project #1, due to the fact that on a man-hours basis, WPPSS #1 is only 60% complete, compared with 75% for #3. If all man-hours had equal value, it would be simple to calculate the capital costs of completion for WPPSS #1 at 25% more than for WPPSS #3, and compute the remaining costs in the manner of this analysis.

Unfortunately, the problem is more complex. First, WPPSS #1 is 100% financed with public utility financing. Due to the absence of depreciation, the lack of federal income tax, and the substitution of an in-lieu-of tax for property tax, the financing costs for WPPSS #1 would be lower than for #3. In addition, during the early efforts to mothball WPPSS 4&5, WPPSS #1 purchased a significant amount of uranium from WPPSS 4&5. This purchase gives WPPSS #1 a much larger net salvage value, but at the same time, a lower operating cost than WPPSS #1, since much of the fuel was acquired at below-market rates.

Work on WPPSS #1 was deferred in June, 1982, about one year before work on WPPSS #3 was halted. At the time work was deferred on WPPSS #1, it was considered to be 60% complete, and #3 was considered to be 50% complete. This relationship would imply that completion of WPPSS #1 could be expected to take only about six months longer than for WPPSS #3, suggesting that the 75% - 60% analysis may be misleading.

This analysis does not assign a different overall cost to complete WPPSS #1 from WPPSS #3. The result of the analysis shows that a decision to resume construction, while highly unlikely if cost-effective alternatives are implemented, need not be made for nine years. In the interim, the risks to completion of each plant are very different. WPPSS #1, while less complete, is located at the Hanford reservation, where public attitudes toward nuclear plants are positive; #3 is at Satsop, a county with a long tradition of anti-nuclear voting, skeptical county and local government officials, and adverse weather conditions.

Additional study is needed to determine if one, or both, of the projects should be preserved or else terminated. The first Plan revision by the Northwest Power Planning Council, scheduled for 1985, would be an appropriate forum for such reevaluation.

IX

QUANTIFYING SUBSIDIES TO NUCLEAR RESOURCES

The nuclear industry benefits from a wide range of benefits, not accounted for in project cost calculation, most of which are provided by federal taxpayers. These external costs include the cost of regulation(NRC), the cost of fuel enrichment not charged under DOE enrichment contracts, research and development underwritten by various off-book accounts, and the limited liability provided by the Price-Anderson act for nuclear operators. All of these should be quantified and internalized in measuring nuclear costs, given the Act's requirement that all direct costs of a resource be counted.

The regional council has internalized subsidies associated with most resources in their 20 year Plan. For example, solar water heater costs were estimated without considering the 40% federal income tax credit available to the owners. In fact, this cost is not borne by regional ratepayers, except in proportion to the region's share of total federal tax revenues. The Council's stated cost-effectiveness criteria considered only costs borne by regional ratepayers:

> "The Council has adopted a perspective which views the "system" as the ratepayers of the region. The Council's cost-effectiveness test is to minimize the total costs borne by the region's ratepayers, both directly and through their utility rates." [Plan, Page 5-1]

Solar might have been found more cost-effective if the federal tax credit "subsidy" had not been internalized. To be consistent, the Council should either recompute the costs of conservation measures net of all available federal subsidies, or else should internalize federal subsidies to WPPSS.

For example, the tax 'savings' to WPPSS from tax-exempt financing is not actually a savings at all (See page G-2 of the Plan). It merely shifts costs from ratepayers to taxpayers. The purchasers of federal bonds, providing funding for BPA conservation programs under 8(d)3 of the Act, must pay federal income tax on the interest they earn.

One area of nuclear subsidies has been clearly quantified, and should be included in estimates of nuclear costs. This is the area of direct federal subsidies to nuclear R&D, fuel enrichment, and regulation. The General Accounting Office reported on these costs in a 1979 report (Nuclear Power Costs and Subsidies, EMD-79-52, June 13, 1979.) Another analysis of nuclear subsidies was completed by Battelle in 1978 (An Analysis of Federal Incentives Used to Stimulate Energy Production, PNL-2410/UC59, March, 1978) and is generally consistent with GAO's analysis.

GAO found that the subsidies in 1976-78 for these three areas totalled about .6 cents/kwh. Assuming escalation in the costs estimated by GAO, and levelization using the Council/BPA methodology, these costs can be internalized in the estimated cost to complete and operation WPPSS #3. Battelle found that subsidies had totalled $15.3-$17.1 billion, or about 2.3 cents/kwh; the Battelle analysis does not lend itself to prospective analysis.

RESEARCH AND DEVELOPMENT

The federal government sponsors nuclear research and development programs at numerous locations, including Hanford, the Idaho National Engineering Laboratory, Los Alamos, Livermore, and Savannah River. GAO found that these efforts consumed $936 million in 1976, rising to $1.2 billion in 1978.

A portion of nuclear research is carried out by the Electric Power Research Institute. Bonneville pays an annual contribution to EPRI from power sales, as to the region's investor-owned utilities. This cost is passed through to ratepayers, but the nuclear portion is not explicitly determinable. GAO did not include this nuclear R&D cost in their estimate.

NUCLEAR FUEL

Nuclear fuel in enriched solely at federal facilities, for national security reasons. WPPSS has 30 year enrichment contracts with DOE. GAO found that DOE has not set rates for enrichment consistent with sound business principles -- specifically, no charge is made for the capital costs of the enrichment facilities. Given DOE's plan to spend as much as $8 billion over the next decade modernizing these facilities, some sort of capital cost and depreciation schedule would appear to be appropriate. GAO estimated the value of this subsidy at $120 million in 1976, rising to $220 million in 1978.

In addition, enrichment uses massive amounts of electricity. For every thirteen kilowatt-hours eventually produced at a nuclear plant, one kilowatt-hour is consumed enriching the fuel used. DOE purchases power from the Tennessee Valley Authority at "melded" rates. Obviously, marginal, not average, costs would be incurred by TVA is fuel enrichment for WPPSS #3 is actually carried out. If marginal costs were used, enrichment costs would approximately double from present levels. GAO did not include this subsidy in their quantification.

REGULATORY COSTS

Unlike many regulatory bodies (state public service commissions, state energy facility siting bodies, the Northwest Power Planning Council, etc) the NRC is not funded through assessments on utility operations. Direct appropriations are made, and the user fees which are imposed recover only a fraction of NRC operating costs. The cost of nuclear regulation can be considered a "quantifiable environmental cost." GAO estimated that more than $200 million per year in regulatory costs were not recovered from the affected utilities.

Table IX-1 shows the effect of the costs quantified by GAO:

TABLE IX-1

COSTS QUANTIFIED BY GAO

YEAR	TOTAL SUBSIDIES ($ MILLIONS)	BILLION KWH GENERATED	MILLS/KWH (NOMINAL)
1976	$1,277	228	5.1
1977	$1,382	243	5.7
1978	$1,656	265	6.2

This stream of costs provides a basis for long-run extrapolation of nuclear subsidy costs provided by federal taxes. Assuming the 1.65% real escalation rate developed by Battelle for nuclear O&M costs (Vol. XIV, Appendix A), and the 6% inflation rate assumed by BPA, the cost of these subsidies is 10 mills/kwh (1980 levelized $). This amount should be included in the estimated cost to complete and operate WPPSS #3.

PRICE ANDERSON ACT

GAO recognized the subsidy value of the Price Anderson Act, and of uranium mining incentives, but did not attempt to quantify the value of these benefits explicitly. In a previous study, the indemnification provided by Price-Anderson was evaluated (Selected Aspects of Nuclear Powerplant Reliability and Economics, RED 76-7, August 15, 1975). Since that time, the insurance requirements for the industry under Price-Anderson have changed.

Nuclear liability indemnification should be considered a quantifiable environmental cost -- that is, a cost which could be internalized, but is not. Assuming that the insurance rates for the level of risk society is exposed to are equal to the insurance rates actually paid for the coverage which utilities do carry, it is possible to quantify this cost. Washington Water Power has reported their annual power plant insurance costs at .4% annually (Record Requisition #13; WUTC Cause U-83-26). Assuming this insurance premium, and the maximum risk a nuclear plant imposes, it is possible to compute a value of this subsidy. Table IX-2 shows a rough approximation of the cost which would be incurred to provide full insurance coverage for nuclear accidents:

Nuclear Subsidies

TABLE IX-2

BENEFIT PROVIDED BY PRICE-ANDERSON INDEMNIFICATION

Maximum Risk: (Rasmussen Report)	$19 billion
Current Insurance Coverage:	$560 million
Uninsured Risk:	$18.44 billion
Insurance Rate:	.4% annually
Annual Insurance Premium:	$73.8 million
Anticipated output;	6.5 billion kwh
Insurance premium/kwh:	11.3 mills/kwh

The amount estimated above can serve as a guide in computing an appropriate environmental cost associated with Price-Anderson indemnification. A different insurance premium rate may be appropriate, and a different maximum risk may apply to the Satsop site. The cost should not be ignored.

TABLE IX-3

TOTAL SUBSIDIES TO NUCLEAR ALTERNATIVES
(levelized 1980$)

R&D/Enrichment/Regulation	10.0 mills/kwh
Price Anderson Act:	11.3 mills/kwh
Subtotal:	21.3 mills/kwh
Environmental costs: (Model Plan pg 57)	20.0 mills/kwh
Total:	41.3 mills/kwh

In order to fully comply with the stated requirements of the Regional Act, the 41.3 mills/kwh should be added to the costs to complete and operate WPPSS #3 identified in Section 1 of this analysis. This analysis has not done so, except for illustration, simply because at the 55-60 mills/kwh in the base case, sufficient resources appear to be available to displace the need for resumption of work on WPPSS #3 in the forseeable future. The costs above generally serve as a "cushion" in the determination that resources costing less than 60 mills/kwh (levelized 1980$) are cost-effective in comparison with WPPSS #3.

TABLE IX-4

COST OF FEDERAL NUCLEAR SUBSIDIES

NUCLEAR SUBSIDIES		GAO ESCALATED AT		
YEAR	NOMINAL SUBSIDY MILLS/KWH	SUBSIDY COST $ THOUSANDS 6.5 BKWH	CONSTANT $ COST/KWH DEFLATED @ 6%	PRES VALUE OF COSTS @ 9.18%
1987	12.04	78445	12.04	78445
1988	12.96	84446	12.22	77346
1989	13.95	90906	12.41	76262
1990	15.02	97861	12.61	75193
1991	16.16	105347	12.80	74139
1992	17.40	113406	13.00	73101
1993	18.73	122082	13.21	72076
1994	20.17	131421	13.41	71066
1995	21.71	141474	13.62	70070
1996	23.37	152297	13.83	69088
1997	25.16	163948	14.05	68120
1998	27.08	176490	14.27	67165
1999	29.15	189991	14.49	66224
2000	31.38	204526	14.71	65296
2001	33.78	220172	14.94	64381
2002	36.37	237015	15.18	63479
2003	39.15	255147	15.41	62589
2004	42.15	274666	15.65	61712
2005	45.37	295678	15.90	60847
2006	48.84	318297	16.14	59995
2007	52.58	342647	16.39	59154
2008	56.60	368859	16.65	58325
2009	60.93	397077	16.91	57508
2010	65.59	427453	17.17	56702
2011	70.61	460153	17.44	55907
2012	76.01	495355	17.71	55124
2013	81.82	533250	17.99	54351
2014	88.08	574043	18.27	53590
2015	94.82	617958	18.55	52839
2016	102.08	665231	18.84	52098
TOTAL:	42.64		15.19	

ESTIMATE FOR
1978 ESCALATED
AT 1.65% REAL FOR PLANT LIFE

SUM OF PV	1932195
AMORT OF PV	98349
1987 MILLS/KWH	15.09
1982 MILLS/KWH	11.28
1980 MILLS/KWH	10.04

AVAILABLE

X

ALTERNATIVE RESOURCES AVAILABLE TO MEET DEMAND CURRENTLY MET BY WPPSS 1/3 IN THE COUNCIL PLAN

If WPPSS 1 and 3 are deferred indefinitely, alternative resources will need to be developed in order to replace the foregone output. A temporary deferral, as proposed by Bonneville in May, allows time for the determination of whether additional resources are likely to become available; immediate construction forecloses this option.

Fortunately, the Plan anticipates such a situation, and identifies nearly 9,000 average megawatts of available resources and prospective load reductions which are not included as resources or options in the Plan. Other studies have identified additional resources; the total of identified additional resources is approximately 13,000 average MW, and is detailed in the section of this report on Optioning of WPPSS #3.

The Council used extremely conservative -- even unrealistic -- assumptions in developing the plan, in part because of the determination that additional coal and nuclear plants would not be needed immediately, and time was available to explore alternatives in detail. The alternate resources identified above far exceed the resource contribution, even in the high forecast, of all new coal plus WPPSS 1&3 combined. Indeed, the Council recognized the conservatism of their analysis on page 5-10, where they stated:

> "If the Council had used less conservative assumptions, no additional thermal plants would be needed in the twenty-year plan."

Given the circumstances at the time the plan was adopted, with no need to even option a thermal plant until 1988, this approach seemed reasonable. With a decision to resume work on WPPSS #3 (#1) now optional, however, it would appear to be imprudent to ignore these resources in making a multi-billion dollar decision.

In identifying a resource implementation schedule in the absence of WPPSS #3, two other adjustments have been made to the load/resource balances shown by the Council at page 6-3 of the Plan. First, WPPSS #1 was assumed to not be completed, as there is little argument that it would be more cost-effective to complete #1 than #3. Second, all new coal has been removed from the resource supply, as the estimated cost of new coal is, at best, not measurably less than the cost of completing WPPSS #3, and probably more expensive. (A consultant to the Idaho PUC concluded in August, 1981, that new coal plants would be a cost-effective alternative to WPPSS #3; considerable work has occurred since that time, and the 1981 analysis may no longer be valid.)

Alternative Resources

SUMMARY OF IDENTIFIED ALTERNATIVE RESOURCES FOR WPPSS 1/3 AND COAL

For the purposes of this analysis, nearly all of the alternative resources which the Council quantified in table 5-1 of the Plan are considered available by the end of the forecast period, and developable at a uniform rate of about 5% per year for 20 years. Some of the resources are removed or adjusted before actual estimates of availability are included in the resource substitution tables in this analysis.

First, the 320 MW of amenity changes the Council identified are excluded; the Northwest Conservation Act Coalition, and the Model Plan, have never advocated measures which may be perceived as changing the lifestyle of Northwest residents. As a practical matter, higher energy costs have had the most drastic adverse impact on lifestyle of any conservation measure to date, and the "amenity changes" may simply reflect a market-determined preference on the part of consumers, trading lower home heating levels for more disposable income.

Third, other resources, such as generation from municipal refuse, geothermal, and wind, which may become cost-effective during the plan period, but were not included by the Council in the Plan, have been excluded from consideration in this analysis as well. In the Provisional Power Plan (Washington State Energy Office, November, 1982), 733 MW of geothermal, and additional 1000 MW of small hydro, 685 MW of cogeneration in commercial buildings, 269 MW of municipal waste energy, and 113 MW of farm animal waste energy were included. The Review and Critique of the Applied Economics Associates Cost-Effectiveness study on WPPSS 2/3 (Don't Bankrupt Washington Legal Defense Fund, January, 1983) identified modifications in retail rate design as a potential 1000 MW resource (half of which is obtained by reducing the penetration rate of electric heat in new construction.)

Table X-1 details a sample of potential and probable resources which for a variety of reasons were not included in the Plan. Subsequent Plan revisions will, undoubtedly, determine which of these are available and reliable.

AVAILABLE

Alternative Resources

TABLE X-1
POTENTIAL RESOURCES NOT INCLUDED IN THE PLAN

RESOURCE	MW	WHERE IDENTIFIED
New Aluminum Technology	3000	Mitsui/WA Senate
Additional cogeneration	1150	Provision Plan
Fluidized bed coal	1300+	Plan, Page 8-5
Additional hydro	1000	Provisional Plan
Additional industrial conservation	1000	Plan, Table 5-1
Abandon Critical Water Planning	1000	Plan, Table 5-1
Appliance Efficiency Standards	1000	Model Plan
Rate design	1000	Review/Critique
Geothermal	733	Provisional Plan
Commercial Lighting	540	Plan, Table 5-1
Commercial Building Code	440	Plan, Table 5-1
Municipal Waste Generation	253	Provisional Plan
Transmission/distribution improv.	250	Plan, Table 5-1
Zone heating/night setbacks	200	Plan, Table 5-1
Add'l hydro from agric. conserv.	165	Plan, Table 5-1
More efficient W.H. Ht. Pumps	160	Plan, Table 5-1
Wood heat increases	120	Plan, Table 5-1
Farm Animal Waste	113	Provisional Plan
Residential conversion standard	103	Provisional Plan
Total:	13,027+	

The resources identified on table X-1 represent a total of 13,000 average MW of energy; each measure is expected to produce at a levelized cost of less than 60 mills/kwh, or competitive with the cost of completion and operation of WPPSS #3. In particular, the measures identified in the Provisional Power Plan were subjected to the same cost methodology used by Bonneville and the Council, and the resulting energy considered by the Washington State Energy Office to be available at 60 mills/kwh or less. (Page 82; Page 118, Provisional Power Plan)

The inclusion of these potentially viable and cost-effective resources allows an additional 13,000 MW to be available to subsitute for WPPSS #3 and new coal. One crucial determination, in using resources not as certain as those in the Plan using existing technology is the date by which the resources must be under construction. This analysis shows, for each of the three relevant Council forecasts (Plan resources other than WPPSS 1/3 or new coal are sufficient to meet all needs in the "low" forecast), that these additional resources are not needed until 1996 in the high and medium-high, and would not be needed at all in the medium-low forecast.

As a result, given a 3-4 year period to complete WPPSS #3, a deferral until at least 1992 would allow time for determination of whether these additional resources would become available.

Alternative Resources

If, for example, by 1986, it were evident that the Mitsui aluminum process would be available, or that additional cogeneration would be available, then the "option" of completing WPPSS #3 would not need to be preserved. Similarly, if load growth followed the "low" or "medium-low" load curve, WPPSS #3 would cease to be a cost-effective option.

OTHER RESOURCES ADDED FOR CONSIDERATION

In addition to the resource conservatisms included from table 5-1 in the Plan, and the additional resources identified in this analysis for other studies, the Council identified a number of resources which are available at costs between 40 and 60 mills/kwh (1980 levelized $). Compared with the base case cost estimate for power from WPPSS #3 with early completion, all of these resources are considered to be available and cost-effective.

These higher cost resources are identified in Appendix K of the Plan, in tables K-12, K-18, K-22, and K-35. The quantity of conservation available but excluded is shown below:

TABLE X-2

40-60 MILL/KWH CONSERVATION IN THE PLAN

	MW
EXISTING RESIDENTIAL SPACE HEAT	90
RESIDENTIAL WATER HEAT	315
NEW RESIDENTIAL SPACE HEAT	55
EXISTING COMMERCIAL	16
NEW COMMERCIAL	7
TOTAL:	483

The total of high-cost (but lower than completion of WPPSS #3) resources available, therefore, is approximately 483 average MW. 85% of this is considered to be realistically achievable, following the arbitrary reductions (in apparent violation of Section 4(f)1 of the Act) used by the Council, leaves approximately 410 average MW of savings. This has been included as a cost-effective resource in substituting resources for WPPSS 1/3 and new coal; to the extent that this may be considered optimistic, additional penetration of the table 5-1 resources would be necessary; a 20% reduction in this 410 MW would require only a .7% increase in the implementation rate of the alternative resources available.

MOBILE HOME STANDARDS

The amount of savings which would result from the imposition of cost-effective standards for mobile homes in the Pacific Northwest (either by regulatory standard, or by incentive payment) was estimated by Battelle (Conservation, Vol. 1, Table 2.10) this showed conservation savings in the year 2000 at approximately 204 average MW available at 60 mills/kwh or less. This is assumed to be also available as a cost-effective resource . The Council recognized this resource, in their table 5-1, but did not quantify the savings, in spite of the quantification which was provided by their consultant.

HYDRO FIRMING WITH COMBUSTION TURBINES

The Council considered hydro-firming with combustion turbines to be an available option for the region. Unfortunately, in computing the cost of hydro-firming, the Plan assumes that new turbines will have to be built for this function, and that exemptions will have to be sought from the Powerplant and Industrial Fuel Use Act (PIFUA).

In fact, firming can occur with the use of existing turbines, at much lower cost. This analysis assumes that existing turbines will be used to firm hydropower in the medium-low and medium-high forecasts, to a limit of 600 MW, the unused turbine capacity under existing licencing, and without need to seek exemption from PIFUA. Tn the event that growth is sustained along the unlikely path of the high forecast, additional turbines could be built, to firm an additional 1000 MW, as proposed in the Plan.

Table X-3 lists the oil and gas fired powerplants, primarily combustion turbines, presently available in the region.

TABLE X-3
EXISTING OIL AND GAS FIRED POWERPLANTS

Beaver	PGE	534	
Bethel	PGE	116	
Harborton*	PGE	227	
Summit	PGE	6	
Whitehorn 1	Puget	68	
Whitehorn 2/3	Puget	177	**
Fredrickson	Puget	178	**
Fredonia	Puget	247	**
Shuffleton	Puget	86	
Whidbey	Puget	28	
Crystal	Puget	3	
Othello	WWP	33	
Northeast	WWP	68	
Wood River	Idaho Power	50	
Lake Union	Seattle	30	
Libby	Pacific	28	
Lincoln	Pacific	36	
	Total:	1915	

* This unit must be moved to a new location before operation can resume.

** Subject to 1500 hour peak load limitation of the Powerplant and Industrial Fuel Use Act.

Of the existing units, 1313 MW are exempt from the Fuel Use Act, and 602 MW are subject. Assuming a 50% capacity factor for the exempt facilities, and 1500 hours/year operation for the subject units, the region can generate a total of about 800 average MW with existing units, without need to seek an exemption to the peak load limitation, an action included in the two-year action plan (Item 19.1). Utilities currently assume about 200 MW from existing turbines under critical conditions (PNUCC, 1983 Northwest Regional Forecast, Page III-7) leaving an additional 600 MW available without the need to either seek exemptions to PIFUA, or to incur additional captial costs.

"Reliability of service" exemptions to PIFUA, allowing use in excess of 1500 hours/year, would increase this capability, subject to the availability of fuel; Puget Power, owner of the plants subject to the fuel Use Act, refused to rule out the potential for a request for a reliability of service exemption (more than 1500 hours) at the time the peakload exemptions were obtained for Whitehorn 2/3, Fredrickson, and Fredonia.

REDUCTION OF DIRECT SERVICE INDUSTRIAL DEMAND

The assumption in Table 5-1 of the Plan that the DSI load could be reduced by 800-1400 MW in the face of doubled real prices in the high forecast does not appear unreasonable. In 1982-83, DSI loads dropped by about 50%. High electricity prices were cited as a reason for the Northwest capacity being shut down.

Bonneville, in their 1983 forecast, is predicting a DSI firm power load of 2656 MW in the year 1994-95; this compares with an estimate of 3405 MW in the same year in the legislative analysis accompanying the Act (Senate report 96-272; page 69 line 11).

Two points need to be made. First, The assumed lower DSI load does not necessarily imply a pro-rata reduction in the amount of aluminum produced, or the amount of employment in this industry. Second, the degree of firmness of power demand in the industry may be reduced by rising prices, as has been observed in the 1981-83 period. Given doubling real prices in the High forecast, there is reason to believe that the DSI's will accept a reduction to one or two firm quartiles, from the present three, in exchange for lower (than would otherwise occur) rates. In fact, this may be the only way to protect the competitiveness of the regional aluminum producers.

As demonstrated in the Model Plan (Page 281-285), the amount of energy consumed per pound of product can be reduced by approximately 25% from current average Northwest plant efficiencies. This would imply a reduction of about 700 MW from current contract levels, or a greater reduction in the amount of usage which this study implies in the High forecast absent WPPSS 1/3 and new coal, assuming equal penetration of all quantified alternate measures (27%).

Finally, the region's DSI's signed new twenty year contracts in 1981. These contracts expire in 2001, and could be renewed at that time with greater interruptibility, or they could NOT BE RENEWED AT ALL. While the Act provides that Bonneville shall sell power to private and public utilities WHENEVER REQUESTED, there is no similar requirement for the Direct Service Industrial customers; The Act required that initial long-term contracts be offered. As a practical matter, new contracts could be offered in 2001 which provided for 100% interruptibility, and could still be challenged as lacking in statutory basis. A change to full interruptibility would be consistent with directive 15 in the Two Year Action Plan, and could reduce firm demand after the year 2001 by a total of 2668 MW in the Medium Low through High Forecasts, and by 1956 MW in the low forecast.

COGENERATION, MUNICIPAL WASTES, GEOTHERMAL

Alternative Resources

The Plan assumes relatively little in the way of cogeneration (500 MW), and no implementation of geothermal or municipal waste generation. In fact, the Plan is internally inconsistent in this regard: the Two-Year Action Plan (item 17.1) directs Bonneville to offer to acquire 10 MW of geothermally-generated energy from a site capable of producing at least 100 MW. The reason that this energy was not included in the Plan is unclear.

No cogeneration was assumed to be developed in new or existing commercial buildings. Given BPA expectations that retail rates for private utilities will continue to increase at or above the rate of inflation indefinitely (BPA Load Forecast Documentation, Supply Pricing Model, August, 1983), this assumption would appear unjustified. The Provisional Power Plan identified over 600 MW in potential commercial cogeneration.

Municipal waste generation is a controversial topic, with unresolved environmental impacts. However, the City of Seattle is aggressively persuing a municipal waste reduction plant, to replace two city landfills which are at or near capacity. The Council has apparently assigned a "zero" probability to this project, as well as to all other municipal waste projects. The Provisional Power Plan assumed that 233 MWe of energy could be obtained from municipal waste, and another 113 MWe from farm animal waste.

While there may be a significant probability that these resources may not be available in the identified quantities, it is inappropriate to therefore conclude that none of them will be available in any quantity. The methodology of this analysis, to determine what proportion of them must be reasonable expected to be available by a point in time when construction would have to resume on WPPSS #3, allows judgment to be applied to the resulting time schedule.

IMPACT OF SUBSTITUTION OF RESOURCES IN THE COUNCIL FORECASTS

Tables X-4 through X-6 show the effect of planning on energy from alternative resources to replace the energy now in the Plan from WPPSS 1/3 and new coal plants, for the High, Medium-High, and Medium-Low forecasts, respectively. In each case, it is possible to meet regional demand without either assuming sudden implementation of alternative programs, or facing large deficits in any year. No analysis has been done for the low forecast, as it is evident from all studies that Plants 1&3 would not be selected as resources in that scenario, even without the addition of alternate resources to the Plan.

In all scenarios, new standards for mobile homes, and inclusion of the 40-60 mill conservation identified in the Plan are assumed. In the high forecast, 85% of the identified resources are assumed to be achievable; due to lower construction activity, lower amounts are assumed available in the lower forecasts. Given the fact that much of this resource is in the form of water heater heat pumps, the availability of the resource should track new construction to some extent.

Once WPPSS 1/3 and new coal are subtracted (Column D), a new load/resource balance is calculated. This determines the total amount of additional resources which must be added (Column E).

The amount of conservation included in the plan, and the amount of that which is in new (G) and existing (J) structures is identified. The amount of potential retrofit conservation (which does not vary by forecast) is identified, assuming that the available resource could be developed in seven years in an aggressive program. The " resource needed with full retrofit" (M) shows the load/resource balance assuming this accelerated conservation program.

The hydro and cogeneration already contained in the plan is identified in (N) and (O). These are assumed to be available, if needed, on an accelerated basis, but at an annual rate of implementation no faster than in the Plan. This implementation schedule is shown in (P). A resource balance with accelerated conservation, hydro, and cogeneration, again using only resources in the Plan, is in (Q).

At this point, resources not acquired in the Plan are introduced. First, both the 40-60 mill conservation (R), and mobile home construction standards are added (S). Existing (T) and new (U) combustion turbines are added as resources. A load/resource balance with these resources (W) , all identified and quantified in the Plan, shows that additional resources are not needed until 1996. To meet load growth beyond 1996, resources not included in the Plan must be added.

The available alternative resources are shown as available in (W), with an assumption made that they can be developed at a maximum rate of 6% per year. By 2002, the entire 12,996 MW is assumed to be available. Actual acquisition of these resources is not needed until 1996 in the medium-high and high forecasts, and is not needed at all in the medium-low. (Y) shows the percentage of available alternate resources which must be developed to meet anticipated load; only 27% of the alternative resources must be developed by the year 2002.

The resource acquisition schedules for the medium-low and medium-high forecasts all are timed to provide a 1500 MW firm surplus for a 15 year period ending in 1997, consistent with the efforts now underway to arrange a long-term firm surplus sale. The export of this amount of surplus is not provided for in the high forecast after 1990; the low probability of this forecast suggests that an "insurance policy" be written into an export contract, providing that the energy to be provided actually be generated at existing oil and gas-fired plants in the Southwest. Such a provision has been widely discussed as one aspect of a surplus sales contract.

Since a determination must be made at least four years before the resources are needed, in order to allow time for completion of WPPSS #3, it appears that a deferral of construction until at least 1992 would be logical.

The scheduling shown on Table X-4 through X-6 is consistent with the resource acquisition plans the Council has identified in Figure 5-10 of the Plan. If the "high" forecast was not evident in 1985, the resources scheduled to be added in 1985 under the high forecast, but not under the other forecasts, could be deferred an additional year, automatically adjusting the regional energy supply to meet demand.

SUMMARY

The 13,000 MW of available resources not included in the plan represent a realistic regional potential. Aggressive action would be needed to develop these, but the potential, including technological innovation, is far in excess of this amount. All of these resources are cost-effective compared with the cost of completing and operating WPPSS #3, using the base case analysis.

Only about one-fourth of these resources would need to be developed to meet regional load under the high forecast, and such a goal should be achievable.

By holding WPPSS 1&3 as resource options for a period of three to five years, as currently planned by Bonneville, a failure to develop the feasibility of these alternate resources after aggressive implementation efforts, would still leave the region free to pursue completion of the WPPSS plants. Completion on the present schedule of the WPPSS projects, however, would foreclose the option of utilizing lower cost resources in their stead.

TABLE 10-4

ACCELERATING THE PLAN'S CONSERVATION
HIGH

YEAR	LOAD	EXISTING RESOURCES	EXIST RES W/O WPPSS 1/3	RESOURCES NEEDED	TOTAL CONSERV IN PLAN	NEW CONSERV IN PLAN	RESOURCES NEEDED W/O 1/3 BUT W/PLAN CONS	RETROFIT AVAILABLE	RETROFIT USED	ADDITIONAL RETROFIT AVAILABLE
1983	16665	17557	17887	-1222	52		-1252	283	50	233
1984	17395	18337	18337	-942	122		-1042	657	120	537
1985	18266	18777	18777	-511	225	126	-613	1091	99	992
1986	19055	19213	19213	-158	358	252	-526	1495	98	1397
1987	19458	19724	18886	572	475	378	97	1859	97	1762
1988	20031	19540	18774	1257	600	524	657	2323	96	2227
1989	20514	20356	18737	1777	750	631	1027	2707	119	2588
1990	21249	22327	18708	2541	875	757	1465	2830	118	2712
1991	21661	20372	18733	2928	1000	883	1528	2830	117	2713
1992	22342	22352	18731	3611	1500	1029	2111	2830	491	2339
1993	23264	20246	18829	4435	2200	1135	2235	2830	1065	1765
1994	23739	19818	18159	5580	2902	1261	2278	2830	1539	1291
1995	24545	19773	18159	6386	3420	1367	2966	2830	2213	617
1996	25522	19787	18250	7272	4000	1513	3272	2830	2487	343
1997	26172	19519	17999	8173	4150	1639	4023	2830	2511	319
1998	26975	19555	17936	9039	4350	1765	4689	2830	2485	345
1999	27762	19517	17808	9954	4550	1892	5414	2830	2658	172
2000	28555	19513	17981	10574	4750	2016	5824	2830	2732	98
2001	29425	19487	17868	11557	4950	2144	6607	2830	2806	24
2002	30183	19465	17646	12537	5150	2270	7287	2830	2830	0

CHANGE IN ANNUAL RETROFIT	RESOURCE NEEDED W/FULL RETRO	ADD PLAN RENEWABLES HYDRO	ADD PLAN COGEN	ACCEL PLAN HYDRO AND COGEN	BALANCE W/ACCEL	40-60 % WILL CONSERV	MOBILE HOME STANDARDS	COMBUSTION TURBINES (EXISTING)	COMBUSTION TURBINES (NEW)
	-1485				-1485				
304	-1529				-1529				
435	-1635				-1635	27	10		
415	-1565				-1565	55	19		
425	-1725				-1725	82	29		
405	-1548				-1548	109	38		
338	-1561				-1561	137	46		
124	-1246			62	-1323	164	57		
1	-875			221	-1225	191	67		
-374	-228			497	-715	219	75		
-574	472			737	-267	245	85	620	
-474	1519	12		1202	483	273	95	622	
-474	2163	71		1191	973	301	105	622	
-474	2929	187		1363	1546	330	114	620	520
-74	3724	337	50	1417	2287	355	124	620	1000
-74	4443	522	150	1417	3226	383	133	620	1020
-74	5142	690	300	1417	3725	410	143	620	1020
-74	5933	900	400	1417	4425	437	152	620	1020
-74	6653	917	500	1417	5165	465	162	620	1020
-74	7237	917	500	1417	5882	493	171	620	1020

TABLE 10-4

	V	W	X	Y	Z
1					
2					
3					
4				% OF AVAIL	
5	BALANCE	NON-PLAN	NON-PLAN	NON-PLAN	BALANCE
6	W/ADDED	RESOURCES	RESOURCES	RESOURCES	WITH ALL
7	MEASURES	AVAILABLE	ACQUIRED	ACQUIRED	MEASURES
8					
9	-1465				-1465
10	-1629	684			-1629
11	-1842	1368			-1842
12	-1979	2052			-1979
13	-1815	2736			-1815
14	-1528	3420			-1528
15	-1745	4104			-1745
16	-1529	4788			-1529
17	-1284	5472			-1284
18	-1010	6155			-1010
19	-1139	6840			-1139
20	-479	7524			-479
21	-27	8208	0	0	-27
22	4	8892	4	0	0
23	208	9576	208	2	0
24	911	10260	911	9	0
25	1573	10944	1573	14	0
26	2222	11628	2222	19	0
27	2940	12312	2940	24	0
28	3557	12995	3557	27	0

TABLE 10-5

ACCELERATING THE PLAN'S CONSERVATION
MEDIUM HIGH

	A	B	C	D	E	F	G	H	I	J	K
5–7	YEAR	LOAD	EXISTING RESOURCES	EXIST RES W/O WPPSS 1/3	RESOURCES NEEDED	TOTAL CONSERV IN PLAN	NEW CONSERV IN PLAN	RESOURCES NEEDED W/O 1/3 BUT W/PLAN CONS	RETROFIT AVAILABLE	RETROFIT USED	ADDITIONAL RETROFIT AVAILABLE
9	1983	16432	17257	17257	-1487	53		-1527	233	53	233
10	1984	16832	18337	18337	-1505	100		-1605	667	100	567
11	1985	17344	18777	18777	-1433	223	55	-1655	1091	139	952
12	1986	17817	19013	19013	-1196	350	172	-1546	1495	178	1317
13	1987	18313	19724	16918	-605	475	256	-1080	1899	217	1682
14	1988	18738	19552	16774	-35	622	344	-635	2502	255	2247
15	1989	19105	22356	18737	371	750	430	-379	2727	330	2397
16	1990	19547	22327	18709	839	875	516	-36	2830	359	2471
17	1991	20047	22372	18753	1294	1000	622	294	2830	398	2432
18	1992	20589	23050	18731	1855	1200	565	658	2830	512	2318
19	1993	21149	23248	18509	2502	1520	774	920	2830	816	2014
20	1994	21715	19318	18199	3516	2000	850	1516	2830	1140	1690
21	1995	22291	19773	18155	4132	2400	945	1732	2830	1454	1376
22	1996	22932	19737	18088	4844	2600	1030	2244	2830	1739	1252
23	1997	23572	19519	17599	5973	3500	1118	2473	2830	1984	846
24	1998	24216	19555	17935	6270	3400	1204	2870	2830	2206	624
25	1999	24641	19517	17698	6943	3650	1252	3293	2830	2358	472
26	2000	25466	19513	17894	7572	3900	1376	3672	2830	2524	306
27	2001	26119	19467	17868	8251	4050	1492	4201	2830	2588	242
28	2002	26679	19455	17846	8833	4200	1548	4633	2830	2652	178

	L	M	N	O	P	Q	R	S	T	U
5–7		RESOURCE NEEDED W/FULL RETRO	ADD PLAN RENEWABLES HYDRO	ADD PLAN COGEN	ACCEL PLAN HYDRO AND COGEN	BALANCE W/ACCEL	43-62 MILL CONSERV	MOBILE HOME STANDARDS	COMBUSTION TURBINES (EXISTING)	COMBUSTION TURBINES (NEW)
9		-1740				-1740				
10	354	-2192				-2192				
11	365	-2612				-2612	21	7		
12	365	-2863				-2863	42	14		
13	365	-2762				-2762	63	21		
14	365	-2883				-2883	84	28		
15	342	-2776				-2776	105	35		
16	84	-2507			62	-2569	127	43		
17	-39	-2138			221	-2359	143	50		
18	-114	-1660			487	-2147	159	57		
19	-314	-1094			727	-1821	192	64	600	
20	-314	-174	18		1020	-1194	211	71	600	
21	-314	356	71		1191	-835	232	78	600	
22	-314	992	157		1393	-401	253	85	600	
23	-314	1627	337	50	1417	210	274	92	600	
24	-314	2246	510	150	1417	829	295	100	600	
25	-164	2892	551	270	1417	1475	317	107	600	
26	-174	3366	833	410	1417	1949	336	114	600	
27	-64	3959	917	500	1417	2542	355	121	600	
28	-64	4455	917	500	1417	3038	382	128	600	

TABLE X-5

	V	W	X	Y	Z
1					
2					
3					
4				% OF AVAIL	
5	BALANCE	NON-PLAN	NON-PLAN	NON-PLAN	BALANCE
6	W/ADDED	RESOURCES	RESOURCES	RESOURCES	WITH ALL
7	MEASURES	AVAILABLE	ACQUIRED	ACQUIRED	MEASURES
8					
9	-1740				-1740
10	-2192	684			-2192
11	-2638	1368			-2638
12	-2919	2052			-2919
13	-2846	2735			-2846
14	-2796	3420			-2796
15	-2587	4104			-2587
16	-2733	4788			-2733
17	-2555	5472			-2555
18	-2373	6155			-2373
19	-2675	6840			-2675
20	-2375	7524			-2375
21	-1745	8208	200	2	-1945
22	-1339	8892	450	5	-1789
23	-759	9576	750	8	-1509
24	-155	10260	1000	10	-1155
25	383	10944	1225	11	-842
26	898	11628	1450	12	-552
27	1462	12312	1700	14	-238
28	1930	12996	1930	15	0

TABLE 10-6

ACCELERATING THE PLAN'S CONSERVATION
MEDIUM-LOW

	A	B	C	D	E	F	G	H	I	J	K
5	YEAR	LOAD	EXISTING RESOURCES	EXIST RES W/O WNPPSS 1/3	RESOURCES NEEDED	TOTAL CONSERV IN PLAN	NEW CONSERV IN PLAN	RESOURCES NEEDED W/O 1/3 BUT W/PLAN CONS	RETROFIT AVAILABLE	RETROFIT USED	ADDITIONAL RETROFIT AVAILABLE
9	1983	16245	17857	17857	-1642	53		-1695	283	50	233
10	1984	16493	18337	18337	-1839	100		-1939	687	100	587
11	1985	16665	18777	18777	-1911	225	57	-2136	1091	159	932
12	1986	17223	19013	19013	-1792	350	114	-2142	1455	205	1250
13	1987	17631	19754	18915	-1287	475	171	-1762	1919	324	1595
14	1988	17995	19580	18774	-778	600	228	-1378	2303	372	1931
15	1989	18324	20355	18737	-413	750	285	-1163	2727	465	2262
16	1990	18597	20327	18723	-11	875	342	-886	2830	533	2297
17	1991	19039	20372	18753	325	1020	399	-694	2850	621	2229
18	1992	19417	20359	18731	635	1125	456	-490	2820	659	2161
19	1993	19912	20246	18639	1183	1250	513	-67	2820	737	2083
20	1994	20247	19818	18199	2048	1375	570	673	2820	605	2215
21	1995	20718	19778	18155	2551	1525	627	1026	2820	888	1932
22	1996	21194	19727	18099	3125	1700	684	1425	2830	1016	1814
23	1997	21615	19616	17999	3519	2025	741	1494	2800	1254	1546
24	1998	22233	19555	17935	4037	2300	798	1737	2830	1552	1278
25	1999	22427	19517	[illegible]	4529	2675	855	1854	2830	1822	1008
26	2000	22872	19513	17954	4978	3000	912	1975	2830	2088	742
27	2001	23346	19487	17833	5480	3325	969	2155	2830	2356	474
28	2002	23733	19458	17846	5912	3700	1026	2212	2830	2674	156

	L	M	N	O	P	Q	R	S	T	U
5	CHANGE IN ANNUAL RETROFIT	RESOURCE NEEDED W/FULL RETRO	ADD PLAN RENEWABLES HYDRO	ADD PLAN COGEN	ACCEL PLAN HYDRO AND COGEN	BALANCE W/ACCEL	40-60 MIL CONSERV	MOBILE HOME STANDARDS	COMBUSTION TURBINES (EXISTING)	COMBUSTION TURBINES (NEW)
9		-1925				-1925				
10	334	-2526				-2526				
11	336	-3255				-3255	14	5		
12	338	-3339				-3339	28	9		
13	333	-3357				-3357	42	14		
14	322	-3379				-3329	56	19		
15	311	-3425				-3443	69	24		
16	55	-3333			88	-3245	83	28		
17	-32	-3365			221	-3144	97	33		
18	-155	-3617			480	-3137	111	38		
19	-48	[illegible]			737	-2897	125	42	600	
20	-43	-3354	18		1030	-2372	139	47	600	
21	-93	-3525	71		1157	-2297	153	52	600	
22	-103	-418	167		1300	-1791	157	55	600	
23	-120	46	227	50	1447	-1369	181	5	600	
24	[illegible]	-23	527	52	1447	-935	[illegible]	[illegible]	[illegible]	
25	[illegible]	344	801	114	1447	-573	209	[illegible]	[illegible]	
26	[illegible]	123	433	428	1447	-137	222	72	600	
27	-188	1351	517	572	1447	224	236	26	600	
28	[illegible]	2155	917	576	1447	429	250	55	600	

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TABLE X-6

	V	W	X	Y	Z
1					
2					
3					
4				% OF AVAIL	
5	BALANCE	NON-PLAN	NON-PLAN	NON-PLAN	BALANCE
6	W/ADDED	RESOURCES	RESOURCES	RESOURCES	WITH ALL
7	MEASURES	AVAILABLE	ACQUIRED	ACQUIRED	MEASURES
8					
9	-1925				-1925
10	-2585	684			-2585
11	-3277	1368			-3277
12	-3435	2052			-3435
13	-3413	2735			-3413
14	-3383	3420			-3383
15	-3455	4104			-3456
16	-3355	4788			-3355
17	-3274	5472			-3274
18	-3235	6155			-3235
19	-3554	6840			-3564
20	-3158	7524			-3158
21	-2581	8208	0	0	-2581
22	-2514	8892	0	0	-2514
23	-2211	9576	0	0	-2211
24	-1818	10260	0	0	-1818
25	-1452	10944	0	0	-1452
26	-1078	11628	0	0	-1078
27	-652	12312	0	0	-652
28	-255	12996	0	0	-255

XI
QUANTIFYING THE LOSS DUE TO EARLY COMPLETION

Early completion of WPPSS #3, as assumed in the three cases analyzed here, would result in an unnecessary increase to the region's short-run power surplus. Bonneville has agreed that surplus energy from WPPSS #3 during the period 1987-92 can not be sold at a price which recovers the incremental construction and operating costs of WPPSS #3 (Testimony before House Interior Subcommittee, June, 1983; 1983 Load Forecast Documentation, Supply Pricing Model, July 19, 1983.) Revisions to BPA's previously estimated cost to complete and operate suggest that the gap may be even wider.

Even in the optimistic analysis, the first year cost of power is 101 mills/kwh -- about five times the average surplus rate anticipated by Bonneville for the same period. Tables VII-1 through VII-2 show both the nominal cost of output from WPPSS #3, based upon the optimistic, base, and pessimistic analyses, and the nominal price for secondary energy, based upon Bonneville's estimates contained in the 1983 forecast.

Alternative resources to WPPSS #3 can be scheduled to come on line as needed, eliminating this problem. Alternatively, low-cost resources such as conservation can be "prebuilt" cost-effectively, if the power they make available can be sold outside (or inside) the region at a price exceeding their acquisition cost.

The loss to the region from bulding and operating WPPSS #3 in advance of regional need can be quantified for each estimate of future load and cost to complete. Tables VII-1 through VII-3 identify the loss to ratepayers associated with selling WPPSS #3 output at surplus rates. The period during which energy would be surplus can only be determined by evaluating each forecast, and each resource acquisition schedule individually. Table XI-1, below, shows the present value of the cost to ratepayers of carrying WPPSS #3 as a surplus resource for a period of three, six, and ten years.

Loss Due to Early Completion

TABLE XI-1

COST TO REGIONAL RATEPAYERS OF EARLY COMPLETION OF WPPSS #3
DISCOUNTED PRESENT VALUE BASIS
PRESENT VALUE IN 1980 $; DISCOUNTED @ 3% REAL
COSTS IN MILLIONS

SCENARIO	3 YEARS	6 YEARS	10 YEARS
OPTIMISTIC	$ 867	$1,536	$2,216
BASE CASE	$1,072	$1,961	$2,891
PESSIMISTIC	$1,112	$2,045	$3,063

Another way to treat this loss during a surplus situation is to treat the loss as an investment. In this way, an accounting "accrual" of interest is added to the loss for each year prior to the time when the output of the project becomes useful to the region. At that time, the investment, made by ratepayers during the surplus period, is treated as a capital cost, and amortized over the remaining period, during which the output will be useful to the region.

That stream of payments can then be discounted and levelized in the same manner as any other project cost, and an additional cost, in levelized mills/kwh, calculated. In doing so, an opportunity cost of capital to ratepayers must be selected. A ratepayer cost of capital rate of 13.7% was used in the capital cost portion of this analysis, reflecting the weighted average cost of capital to public and private utilities. Using this amount here, Table XI-2 shows the cost of the surplus, in mills/kwh, for the above conditions; A 10% probability of the high and low forecasts, and a 40% probability of the medium-low and medium-high forecasts was used.

TABLE XI-2

COST TO REGIONAL RATEPAYERS OF EARLY COMPLETION OF WPPSS #3
ACCRUAL UNTIL REGIONAL NEED BASIS
EXPRESSED IN LEVELIZED 1980 MILLS/KWH
OVER USEFUL PLANT LIFETIME

SCENARIO	3 YEARS	6 YEARS	10 YEARS	EXPECTED VALUE
OPTIMISTIC	12	24	43	19
BASE CASE	15	31	56	24
PESSIMISTIC	16	32	62	27

Loss Due to Early Completion

SURPLUS SALES PRICE

The above analysis assumes that the incremental price the region will receive for the surplus energy generated by WPPSS #3 in an early completion situation is equal to the average surplus rate estimated by Bonneville. Experience shows that this is an optimistic assessment. Tables VII-1 through VII-3 include an analysis of the loss to regional ratepayers, if power from WPPSS #3 is sold at Bonneville's estimated surplus power rates, based upon the Supply Pricing Model incorporated in the 1983 Load Forecast. The value of surplus energy does not equal the cost of producing the power at any time during the period of BPA's analysis -- through 2005.

As the supply of surplus energy increases, the value of all surplus sales drops. At present, whenever the region is in a "spill" or "imminent spill" situation, the price of surplus energy drops sharply, as sellers compete for a limited export market. In this situation, an incremental addition to the region's surplus energy can actually lead to a decrease in total revenue from surplus sales.

The current capacity of the Southwest intertie is approximately equal to the average non-firm surplus of the region. This suggests that even with load/resource balance, the region will be in a spill or imminent spill situation much of the time. Early completion of WPPSS #3, exacerbating the firm surplus situation, will clearly make this occur more often. As a result, using the average surplus rate as a proxy for the incremental surplus rate tends to understate the costs of early completion to ratepayers.

Applied Economic Associates estimated surplus sales revenues based upon an estimate done by Bonneville in 1982 (Cost-Effectiveness Study of WPPSS 2/3; Page VI-99). This estimate, however, did not assign a value to a surplus in excess of 1500 MW -- approximately one-third of the average non-firm surplus, or one fourth of the total anticipated surplus if WPPSS #3 is completed on schedule.

A decision to delay WPPSS #3 eliminates the need for the computation made here, as the project would not be timed in such a manner to exacerbate the firm power surplus.

TOTAL COST OF WPPSS #3 INCLUDING ALL ADJUSTMENTS

The total cost of completion and operation of WPPSS #3 must include the direct costs of power, the loss to ratepayers during a surplus period, plus both subsidies and environmental costs. While the Council has ignored the latter two categories, along with the costs of transmission, distribution, and associated losses, it is important to show these costs as well. Consideration of alternate resources in this analysis is limited to resources with costs of 60 mills/kwh or less (1980 levelized $), so the inclusion of subsidies, environmental costs, and transmission/distribution losses is not critical to this analysis.

Table XI-3 shows the levelized cost of power from WPPSS #3 with the loss due to surplus generation internalized. The costs of federal subsidies and environmental costs are shown separately, to detail the total cost of completion and operation (except for transmission costs and losses) for the project:

TABLE XI-3

TOTAL COST FOR WPPSS #3 WITH ALL COSTS INTERNALIZED
1980 LEVELIZED MILLS/KWH

	OPTIMISTIC	BASE	PESSIMISTIC
BUSBAR COST:	45	56	74
LOSS FROM SURPLUS:	19	26	27
Subtotal:	64	82	101
SUBSIDIES:	21	21	21
ENVIRONMENTAL:	20	20	20
Subtotal:	105	123	142
Transmission:	5	5	5
Losses @ 8%:	9	13	15
Total:	119	141	162

XII
BENEFITS OF HOLDING WPPSS #3 AS A RESOURCE OPTION

One of the major determinations of the Regional Plan is the notion that potential resources can and should be held as options. In particular, the plan recommends that options be sought on small hydro projects, cogeneration installations, and coal projects. The theory is that an option can assure resource availability in the future, allow necessary permits to be secured, but defer actual construction costs until an actual need for the power develops.

One reason the Plan prefers coal plants to nuclear is that they can be built in a shorter period of time, and the "hold" costs on options is smaller. These two issues, however, do not apply equally to WPPSS #3 as to nuclear units in earlier stages of completion.

Direct construction on WPPSS #3, once resumed, is expected to take approximately three and one half years; this is a shorter period of time than for a new coal plant. The "hold" costs for the physical assets are estimated by WPPSS at approximately $40 million per year. While not inexpensive, this is a small fraction of the $3.2 - $4 billion needed to complete the project, and is less than the typical preconstruction licensing cost of a new coal plant.

In addition, an immediate restart of WPPSS #3 poses significant problems which would diminish following a delay of three or more years. First, present financing difficulties could be resolved, and lower cost borrowing achieved. Second, key project personnel have left the site and taken positions at other nuclear construction projects. Third, consumer opposition to the project (and their ability and willingness to pay for it) may subside if rates level out as Bonneville projects; on the other hand, if rates continue to spiral, all regional load forecasts will require revision, and the output of the project may not be needed. Finally, a delay may allow additional resources not presently felt to be "reliable and available" to be "proven up." To pursue construction on a high-cost project, while ignoring possible technological innovation would seem unwise.

FINANCING WPPSS #3

Construction to date on project #3 has been financed through the issuance of long-term tax-exempt bonds for 70% of the plant, and through a combination of equity issues and debt issues by the private utilities for their 30%. While the private utilities remain capable of providing financing (albeit at record real rates for both debt and equity), the default on project 4/5 bonds has made it essentially impossible for WPPSS to obtain conventional financing for the remaining 70% of the project.

WPPSS PLANT 3 AS A RESOURCE OPTION

Three different penalties would currently apply to financing for an immediate restart; some or all of these will abate after a period of delay. One is the penalty associated with current record real interest rates; a second is a "WPPSS" penalty being assessed by the current market; the third is the loss of tax-exempt bonding capability by securing financing through an entity different from WPPSS.

The first penalty is that being experienced by all long-term debt issues in the current market -- record real interest rates. This problem is adequately demonstrated by consideration of current, past, and projected home mortgage rates. Table XII-1 shows the inflation rate, the home mortgage rate, and the "real" interest rate for the period 1978-85; the prospective estimates were developed by the Washington State Office of Financial Management:

TABLE XII-1

LONG-TERM MORTGAGE RATES, 1978-85

YEAR	INFLATION (OFM)	MORTGAGE RATE (NOMINAL)	MORTGAGE RATE (REAL)
1978	7.6%	9.7%	2.1%
1979	11.3%	11.3%	0%
1980	13.5%	14.0%	.5%
1981	10.3%	16.7%	6.4%
1982	6.2%	16.6%	10.4%
1983	3.0%	13.0%	10.0%
1984	4.6%	12.4%	7.8%
1985	5.0	13.1	8.2%

Source: Washington Office of Financial Management, Economic and Revenue Forecast, June, 1983

The same historical relationship has existed for private utility borrowing rates. The table below shows the debt costs for the Washington/Oregon private utilities during the period 1978-82. The issues included in TABLE XII-2, below, are samples, and do not represent a rigorous analysis of private utility debt costs.

WPPSS PLANT 3 AS A RESOURCE OPTION

TABLE XII-2

PRIVATE UTILITY LONG-TERM DEBT RATES 1978-83
(Northwest Regional Utilities)

YEAR	INFLATION (OFM)	BOND RATE (NOMINAL)	BOND RATE (REAL)	UTILITY ISSUING
1978	9.4%	9.7%	-.3%	PGE
1979	11.3%	12.625	1.425%	PUGET
1980	13.5%	14..75%	1.25%	UTAH POWER
1981	10.3%	14.125%	3.175%	WWP
1982	6.2%	15.75%	9.55%	WWP
1983	3.0	13.25%	10.25%	WWP (Est.)

Source: Utility Annual Reports, 1978-82;
WWP Testimony to Wash. UTC, 1983

As is evident, interest rates at the present time are far in excess of those which existed during the earlier period of construction on WPPSS #3. A decision to build now would entail the sale of securities (if possible) at very high fixed rates. If interest rates subside, the fixed cost debt will remain. The other possibility is that real interest rates will not come down; if this is the case, there is reason to doubt that economic expansion will be sufficient to justify completion of the plant at all. The long-term interest rate paradox is something of a "Catch-22" for a decision to restart the plant in the immediate term.

If the project is financed at current rates of 8-10% real, compared with an assumed 3% real cost under "normal" circumstances, the additional interest on borrowing would amount to $100 million per year for 30 years; even assuming a 3% real discount rate over the project lifetime, this adds a present value of approximately $1.8 billion to the total cost of the plant, far exceeding any estimates of the cost of delay.

The cost estimates for all three scenarios are based upon current market interest rates, as they all assume a July, 1984 restart. Further delay would add escalation of about $60 million per year to the cost of the plant, together with "hold" costs of about $40 million; if a four year delay allowed financing on reasonable terms, however, the return would be four times the cost.

The second penalty is the so-called "WPPSS Penalty," an assessment being made against WPPSS due to the problems created by the default on WPPSS 4/5 bonds. Four studies of interest penalties have been undertaken. Each has concluded that default would bring interest penalties on utility revenue bond financing, and each found that these penalties would subside over time. These studies are as follows:

WPPSS PLANT 3 AS A RESOURCE OPTION

Oregon Municipal Debt Advisory Committee: Survey of financial Community

Washington Public Interest Research Group: The Many Prices of Default

Knight-Bonniwell: Final Report to the Governor

Washington Research Council: What Happens to Local Government if WPPSS Defaults?

While it is difficult to assess the magnitude of penalties which would be assessed against a separate entity financing completion of WPPSS #3, it is clear that such an entity would have a limited market for securities, and would therefore pay higher interest rates than a comparably-rated security without the WPPSS stigma. It is equally difficult to assess the degree to which time would reduce this penalty.

It is, however, reasonable to assume that the penalties would subside if the present effort by WPPSS 4/5 bondholders to attach the assets of WPPSS 1/2/3 fail. If these efforts are successful, Bonneville will be in a position of having to help repay the WPPSS 4/5 bondholders, and the ability of Bonneville to generate sufficient revenues to repay the security holders of the new "entity" would be less certain. Only a delay allows for the resolution of this issue, and the consequent removal of the spectre of risk which is contributing to the current "WPPSS Penalty."

The current obstacle to conventional tax-exempt financing of WPPSS #3 is the current legal confusion surrounding the WPPSS 4/5 default. Legislation (S-1701) has been introduced in the U.S. Senate to allow creation of a separate "entity" to finance completion of the net-billed thermal plants. This entity, it is generally expected, would obtain funds from the corporate securities market, rather than from the municipal market. While the taxable market is larger, and therefore easier to finance multi-billion dollar projects in, the loss of tax-exemption would be expected to add significantly to WPPSS' borrowing costs.

It has been proposed that the "entity" would finance with short-term securities, carrying floating interest rates. This, it is said, will allow the interest rates to remain in the 11%-13% range, even though the bonds would no longer be tax-exempt. To utilize such interest rate estimates would be inconsistent with the use of long-term rates for evaluating other resources in the Plan. Assuming short-term rates for all resources would make all capital-intensive resources -- particularly including conservation -- much less expensive.

WPPSS PLANT 3 AS A RESOURCE OPTION

Perhaps most important in this regard is the fact that using short-term credit would expose the region to a potentially unmanageable risk when the securities must be rolled over. The Snohomish County PUD is facing a potential crisis with respect to the rollover of the short-term financing for the Sultan Dam project. Both Bonneville and the WPPSS Executive Board have indicated that short-term financing is not acceptable. There are also legal impediments to short-term financing. (See Section 4, Chapter 1, Laws of 1981, 1st Ex. Sess.)

Typical short-term tax-exempt interest rates seldom have exceeded the rate of inflation, implying zero or negative real costs of capital.(See Model Plan, appendix 1). Therefore, consideration of short-term interest rates would require extensive rework of the Plan itself -- something the Council has indicated an unwillingness to do as a part of the analysis of the cost-effectiveness of WPPSS #3.

A period of delay would allow current record real interest rates to subside, and allow the region to finance plant #3 (if needed) at more moderate interest rates. The potential savings are significant: a 3% reduction in long-term interest rates on the $2 billion cost of completion of WPPSS #3 would save ratepayers $60 million annually for the 30+ year term of the issue. The present value of such a stream of savings is approximately $600 million assuming a 3% discount rate. This savings alone more than offsets the entire cost of delay, including the interest during construction on the 30% of the project held by the private utilities.

KEY PROJECT PERSONNEL

Since the construction slowdown at Project #3 began in April, 1983, key project personnel have left the site. The "Brain Drain" has been one cause for concern that an extended delay would result in project termination -- due to an inability to secure qualified construction managers.

This issue has been dealt with in part by WPPSS, in their decision to include $38 million per year in "preservation costs" in the delay budgets. This amount is felt by WPPSS to be sufficient to keep key personnel on the staff throughout the delay period (testimony of Jerry Read, Controller, NW Power Planning Council, September 7, 1983).

However, delay may enhance the ability to recover certain personnel who have left the site. Most of the people who have left the site have taken positions at other nuclear projects. By and large, these projects will be through the construction phase, and in either start-up testing or commericial operation by a 1985-87 restart of project #3. Therefore, it is likely that many of the key personnel who have left the project #3 site will become available again after a period of delay.

WPPSS PLANT 3 AS A RESOURCE OPTION

One person often credited with improving the construction progress at #3 is R.S. (Mike) Leddick, the project #3 Program Director from 1981-83. Leddick has left the site, and taken a position with Louisiana Power and Light Company, at their Waterford #3 site. This project is scheduled for commercial operation in November, 1984. It is unlikely that Mr. Leddick would consider a return to WPPSS prior to the completion of that job. Waterford #3 is a type 2e Combustion Engineering plant -- the same model as WPPSS #3. The experience in start-up of a similar plant would clearly be an advantage in the completion of WPPSS #3.

Only three other "sister" plants to WPPSS #3 are still under construction. Those are Palo Verde 1/2/3, in Arizona. These three plants are scheduled for commercial operation in 1984-87. After completion, it is reasonable to anticipate that the experienced workers who have completed Palo Verde would be available to assist with completion of WPPSS #3.

To restart the project immediately would require re-recruiting many workers who have left the site. Those who have taken other positions elsewhere in the country can be expected to be hesitant to leave secure employment elsewhere, and resume work at a project where completion, even with restart, is less than certain. After a period of delay, however, as construction work is completed at other nuclear plants, workers will become available, and be willing to relocate. Virtually every nuclear plant on which construction is actively underway is now scheduled for commercial operation by 1987-88, implying that a delay would allow WPPSS to select the best workers from a number of plants around the country (See: Commercial Nuclear Power Plants, Edition 14, NUS Corporation, January, 1983)

Only a continued delay on WPPSS #3, under the Council's "Option" concept, would allow WPPSS the "pick of the industry" for project personnel if work were to be resumed. Immediate restart would logically involve higher construction costs, due to lower quality personnel.

CONSUMER ACCEPTANCE

One obstacle to an immediate restart is the consumer perception that WPPSS is an incompetent organization, that the power is not needed, and that the rate spiral must be halted. Congressional action has been delayed on the legislation intended to facilitate financing of WPPSS #3 pending a "regional consensus." This consensus cannot be forged unless and until the rate impacts are better understood, and the power need is more clearly evident. Resuming of construction during a period of surplus power capability is inconsistent with the concept of regional consensus.

WPPSS PLANT 3 AS A RESOURCE OPTION

Ratepayers have seen rate increases of more than 20% annually since 1979. While Bonneville has indicated that rates will rise more slowly in the years to come, one input to that analysis is an assumed deferral of WPPSS #3. In the June 22, 1983 Budget Submittal to Congress, BPA indicated that their required "Revenue from Operations" would increase from $2.8 billion in fiscal year 1984 to $4.1 billion in 1987. The budget submittal was subsequent to the analysis (May 24) which led to the recommendation for deferral of project #3. This 46% increase in BPA revenue requirement casts doubt on the stability of BPA rates during the next four years.

The BPA forecast released in August, 1983 includes an estimate of rates, which in turn, influences regional power demand through assumed elasticity rates. The BPA power sales in that forecast, by class, multiplied by the assumed rates in that forecast, by class, produce only $2.8 billion. Transmission revenues (not predicted by the forecast) presently add $60 million annually to Bonneville's coffers. The remaining $1.2 billion discrepancy could mean that BPA's rates must increase by another 30-50% above levels now predicted by Bonneville.

If rates by 1988 were to increase by 50% above levels assumed in the current forecast, BPA sales would be reduced by approximately 8 billion kwh (assuming -.2 elasticity). This exceeds the anticipated output of project #3, implying a longer power surplus without the project, and an smaller probability that the output will be needed at all during the anticipated project lifetime.

While BPA may revise their anticipated revenue requirement again in the near future, and make a new budget submittal to Congress, ratepayers must be certain that rates have stabilized before supporting renewed construction expenditures. At least one utility is anticipating that BPA rates will increase by 22% annually for an indefinite period in making their own resource plans (see: Minutes of Mason County PUD #3 meeting on Skokomish Dam project, October 3-4, 1983).

A project delay would allow rates to stabilize as anticipated. If rates continue to rise, the need for the project output will be reduced, due to elasticity not included in present forecasts.

Consumer opposition to the project cannot be expected to diminish until annual rate increases subside. This Winter, BPA's rates will be 7 mills/kwh higher than last winter, and 14 mills/kwh higher than the winter of 1981-82. Retail rate increases prior to the Winter of 1981-82 resulted in the "ratepayer revolution," where tens of thousands of ratepayers rallied against rate increases, and new PUD commissioners were elected statewide.

AVAILABLE

ADDITIONAL ENERGY RESOURCES MAY BECOME AVAILABLE

The Plan does not assume any innovation in any energy production or conservation areas other than assumed improvements in nuclear performance and cost trends. In fact, rising energy costs worldwide are spurring technological innovation in both production and consumption technologies.

The inconsistent treatment in the Plan is unexplained. Nuclear plant availability is assumed at 65%, in spite of national performance averages for large plants of 55%; fuel utilization is assumed to improve from the historical average of 24,000 MWDt/MTU to 33,000 MWDt/MTU. The historical 12% real escalation in O&M costs is expected to subside to 1.65%. Other improvements are assumed as well, and are detailed in the specific analysis of WPPSS #3 costs in this report.

No innovation has been assumed in other energy areas. The Plan specifically used only "currently available" technologies for producing and conserving electricity. For example, while "fluidized bed" coal plants were found to have lower construction and operating costs than conventional coal plants, they were not considered in the resource portfolio for the Plan, as the Council felt this is an "emerging" technology.

This and other resources may become available in the near future. To assign a "zero" probability to all resources not currently available is to ignore the reality of recent years, when energy production and conservation technology has moved ahead rapidly.

A delay, obviously, would allow further "emergence" of other technologies. Table X-1 listed certain resources identified both in and out of the Plan, and the amount of energy anticipated to be available at costs lower than that of a new conventional coal plant. Delay would permit these resources to be "proved up"; immediate construction would eliminate this potential option.

It is no more logical to assume that NONE of the 13,000 MW of resources in Table X-1 will be successfully developed (as the Council has effectively done in the Plan) than it would be to assume that ALL of them would become available. Some positive probability must be applied to each alternative resource; doing so will allow the region to plan on some amount of energy becoming available as a result of technological innovation.

The list of resources above, while by no means exhaustive, does provide an indication of the amount of alternate resources which may become available. One way to deal with the uncertainty of their availability is to determine a date by which they must become available, or else substitutes (such as the completion of WPPSS #3, or the construction of new coal plants) must be initiated. This approach is taken in the

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section of this analysis on Scheduling of Resources to Replace WPPSS 1&3.

Holding WPPSS #3 as an option allows for the emergence of these new technologies (or the development of experience with existing technologies, such as appliance efficiency, commercial building codes, and wood heat); completing the plant on an accelerated schedule may preclude the development of lower-cost, environmentally preferable options.

CONCLUSION

A resumption of construction on WPPSS #3 would be extremely difficult to achieve without a project delay. Financing, if available, would be extremely expensive. A delay would greatly reduce financing costs.

The availability of quality construction personnel would improve if work was not restarted until such time as construction work on other nuclear plants nears completion, and the workers on other sites are seeking new sources of employment; to attempt to bring back key project personnel who have accepted positions elsewhere would likely meet with little success, due to continuing uncertainties.

Consumer opposition this Winter may make project restart impossible; a delay until rate increases subside would allow time to build a regional consensus for the project.

Finally, a delay will allow time for further study of emerging technologies, and the development of experience with the resources included in the Plan, to determine if some additional resources can be expected to be available, or if some resources included in the Plan should be deleted.

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October 24, 1983

The Honorable James Weaver
Chairman, Subcommittee on Mining, Forest Management,
and The Bonneville Power Administration
1626 Longworth House Office Building
Washington, D.C. 20515

Dear Chairman Weaver:

On behalf of the Northwest Power Planning Council, I am submitting written responses to your subcommittee's questions dated October 12, 1983.

The topics to be covered by your subcommittee's hearings on October 27 and 28 are very important for the Pacific Northwest. The Council is especially interested in the cost-effectiveness of the WPPSS plants; BPA's efforts to implement the Northwest Conservation and Electric Power Plan adopted by the Council on April 27, 1983; BPA's Environmental Impact Statement regarding the effects of its residential weatherization program on indoor air quality; and BPA's long-term conservation contracts. Unfortunately, the timing of the hearings presents a problem for the Council. The Council has not yet taken a formal position on the first three topics and has nothing new to report at this time on the fourth.

The Council staff will release an issue paper on the staff's analysis of the cost-effectiveness of the WPPSS plants on October 26, 1983. The Council is scheduled to hear public comments and consider the staff's report on November 2, 3 in Seattle. The Council has not yet taken a position on this matter and does not plan to do so until interested parties in the region have had an opportunity to comment on the staff's work. A copy of the staff issue paper will be express mailed to your subcommittee as soon as it is available.

BPA's implementation of the Council's Plan is also an important issue for the region. The Council requested a workplan and schedule from BPA by August 1, 1983. On August 15, 1983, BPA issued its "Implementation Programs for the Northwest Power Planning Council's Two-Year Action Plan." On August 31, 1983, the Council staff prepared an issue paper which contained preliminary staff conclusions that 1) BPA had committed to act consistently with the Council's Plan (with three specific reservations); 2) the response on the conservation program contained significant differences from the Plan and may not be consistent with BPA's commitment; and 3) the

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response on other resource actions varies from the Plan in some respects but appears to be consistent with BPA's commitment. The issue paper also detailed the differences between BPA's response and the Council's Plan.

On September 6, 1983, the Council directed its staff to consult with BPA to identify precisely all disagreements and to resolve as many problems as possible. On September 28, 1983 the staff provided a status report on the consultations with BPA. Both issue papers are attached for your information.

The Council staff has requested detailed information on BPA's workplan by November 15. The Council is expected to consider the adequacy of BPA's response at its December 14, 15 meeting. A copy of the letter listing the information the staff has requested is attached.

A major concern of the Council at this point is BPA's ability to borrow from the U.S. Treasury to pay for the conservation programs in the Council's Plan. The Council has written to both the Administration and the Northwest Congressional delegation stating that this borrowing flexibility is critical to the region's ability to meet its power needs. Copies of those letters are attached.

Another topic that may significantly affect the implementation of regional conservation programs is BPA's August 1983 Environmental Impact Statement regarding the effect of BPA's residential weatherization program on indoor air quality. The Council staff is currently reviewing the EIS and the Council is scheduled to consider the staff's recommendations for comments on the EIS on November 2, 3. The comment period closes on November 14.

Given the status of these issues, we are providing your subcommittee with all of the information that has been prepared to date. The Council looks forward to testifying before your subcommittee after it has adopted positions on these issues.

Please do not hesitate to contact me if you or your staff have questions or need additional information.

Sincerely,

Edward Sheets

Edward Sheets
Executive Director

Enclosures

NORTHWEST POWER PLANNING COUNCIL

RESPONSES TO QUESTIONS FROM THE U.S. HOUSE OF REPRESENTATIVES SUBCOMMITTEE ON MINING, FOREST MANAGEMENT AND THE BONNEVILLE POWER ADMINISTRATION

October 24, 1983

QUESTION 1.

The Northwest Conservation and Electric Power Plan states:

> Rate designs should place heavier emphasis on energy charges and less emphasis on demand and customer charges. Because of the operating characteristics of the regional hydropower system, the binding constraint on the system is expected to be meeting energy loads rather than meeting peak demands.
>
> . . .
>
> In reference to wholesale rates, the Council recommends that Bonneville make its rate designs at the wholesale level consistent with the goal of giving individual wholesale customers the most appropriate price signals about future costs of electricity. In particular, given the nature of the hydropower system, further shift toward increased energy charges and reduced demand charges would be appropriate in the future.

Are the rate adjustments announced by BPA on September 30 consistent with this recommendation?

RESPONSE TO QUESTION 1:

The issue of Bonneville's proposed rate structures and their consistency with the Plan was raised at a public Council meeting in Spokane on July 7, 1983. At this meeting Council members discussed their positions on various issues in the Bonneville rate case, preparatory to filing a statement in the rate case.

The Council's rate recommendations in the Plan called on Bonneville to shift its emphasis away from demand charges and toward energy charges. The Plan also states the following about the Council's retail rate design recommendations:

> The aggressiveness with which these rate designs should be implemented will depend on the duration and saleability of the current firm surplus and the revenue problems attendant on the surplus.

In response to its revenue stability problems, though it made no mention of the Plan, Bonneville has increased its demand charges a greater percentage than it has increased its energy charges in this year's case.

After discussions at the July 7 meeting, there was a consensus by the Council not to raise this issue in the Council's comments on the rate case. The decision does not represent a divergence from the long-term Council recommendations for BPA wholesale rates and the Council does not expect this allocation of cost between demand and energy charges to represent a trend in BPA ratesetting policy.

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In deciding not to comment on this matter the Council recognized that BPA is facing revenue problems and a substantial surplus of electricity. The Council did not agree that increased demand charges and decreased energy charges are necessarily the best way to deal with revenue stability problems.

QUESTION 2.

What are the conclusions of the Council's most recent analyses of the cost-effectiveness of resuming construction of WPPSS 3? Please provide the important assumptions and methodology used to derive these conclusions.

QUESTION 3.

How soon could construction resume at WPPSS 3? If any key managers of the project have been lost, how long would it take to replace them? How much of the workforce (managerial and manual) has been laid off or terminated? How many of these persons have left the Satsop area for work elsewhere?

QUESTION 4.

Under each of the Council's four load forecasts, is it economical to--

a. restart construction on WPPSS 3 as soon as possible?

b. resume construction of WPPSS 3 after a period of preservation?

c. terminate WPPSS 3?

RESPONSE TO QUESTIONS 2, 3, 4:

The Council has not taken a position on these questions. The Council expects to conclude its study on the cost-effectiveness of the alternative schedules for completing WPPSS plants 1, 2, 3 by November 3, 1983.

The Council staff is scheduled to release an issue paper on October 26, 1983 that describes the analysis that has been conducted, the assumptions and methodology used by the staff, and the staff's recommendations. In addition, the issue paper will seek specific public comment on a number of important issues. A copy of the issue paper will be express mailed to the subcommittee as soon as it is available.

The staff issue paper is the result of staff analysis and consultation beginning in August. Since that time, the staff has provided status reports to the Council and the public on September 6 and 22 and October 5 and 20. In addition, Council Members and staff have met on several occasions with representatives of all the groups interested in this issue.

The Council is scheduled to hear public comment on the staff issue paper and consider the staff recommendations on November 2, 3. We will forward a copy of the Council's report as soon as it is available.

QUESTION 5.

Is BPA conscientiously implementing the conservation components of the Council's two-year action plan? Please indicate any and all specific failures of BPA to implement the plan. Is BPA's reluctance to implement these measures in any respect well founded?

RESPONSE TO QUESTION 5:

When the Council adopted the Northwest Conservation and Electric Power Plan on April 27, 1983, it identified 96 conservation actions for BPA implementation. These programs are designed to enable BPA to acquire the most cost-effective resources throughout the full 20 years of the plan. This includes the ability to meet rapid economic growth with the least costly resources available.

The Council requested a schedule and workplan from BPA by August 1, 1983 describing how these actions would be accomplished. Based on BPA's August 15, 1983 document entitled "Implementation Programs for the Northwest Power Planning Council's Two-Year Action Plan" it appears that BPA is presently implementing 10 of the 96 conservation action items in the Council's Two-Year Action Plan. These efforts include the on-going regional residential weatherization program for existing buildings (Action items 1A, 1B, 1D, 1G, 1J, and 1.1(a)), the Hood River demonstration project to test conservation delivery systems (partial implementation of Action item 1.3), and state and local technical and financial assistance and coordination (Action items 12.10 and 12.12).

BPA has stated that implementation of 74 of the Council's conservation actions cannot be assured because of limitations imposed on BPA borrowing from the U.S. Treasury and reduced expectations of the amount of financing available to BPA from non-Federal sources. In addition, BPA identified 12 conservation actions it could not do as specified and requested further consultation.

On August 31, 1983 the Council staff prepared an issue paper on BPA's implementation of the programs which contained preliminary staff conclusions that 1) BPA had committed to act consistently with the Council's plan (with three specific reservations), 2) The response on the conservation program contained significant differences from the Plan and may not be consistent with BPA's commitment, and 3) The response on other resource actions varies from the Plan in some respects but appears to be consistent with BPA's commitment. The issue paper also detailed the differences between BPA's response and the Council's Plan.

On September 6, 1983, the Council directed its staff to consult with BPA to identify precisely all disagreements and to resolve as many problems as possible. On September 28, 1983, the staff provided a status report on the consultations with BPA. Both issue papers are attached for your information.

The Council staff has requested detailed information on BPA's workplan by November 15. The Council is expected to consider the adequacy of BPA's

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response at its December 14, 15 meeting. A copy of the letter listing the information the staff requested is attached.

A major concern of the Council at this point is BPA's ability to borrow sufficient funds from the U.S. Treasury to pay for the conservation programs in the Council's Plan. The Council has written to both the Administration and the Northwest Congressional delegation stating that this borrowing flexibility is critical to the region's ability to meet its power needs. Copies of those letters are attached.

The Council has been informed that the Office of Management and Budget has recently turned down BPA's request for additional borrowing authority from the U.S. Treasury and that the Department of Energy is appealing that decision. The Council is continuing its efforts to communicate the importance of this additional borrowing authority to the Administration.

QUESTION 6.

What are the Council's recommendations for improving the acceptability of BPA's long-term conservation contract offers?

RESPONSE TO QUESTION 6:

The Council outlined its recommendations for bringing BPA's long-term conservation contract into conformance with the Plan in a May 17, 1983 letter to BPA (letter and supporting memorandum attached).

Subsequently, BPA informed potential contractors that the present contract would be reviewed and amended to bring it into compliance with the Council's stated objectives in the Plan.

BPA has established a group which includes Council staff to develop specific amendments. At this time, BPA staff envisions a packaging of amendments to the current weatherization program which can be integrated as a whole into the regional program at the beginning of FY 85.

QUESTION 7.

Does the Council agree that implementation of residential weatherization measures should be restricted in order to reduce adverse impacts on indoor air quality?

RESPONSE TO QUESTION 7:

The Council has not made a determination on the indoor air quality issue.

The Council staff is currently reviewing BPA's Draft Environmental Impact Statement for the Expanded Residential Weatherization Program (August 1983) and other related data.

Council staff is preparing a draft position paper for presentation to the Council at its November 2 & 3, 1983 meeting.

We will forward to you a statement of the Council's formal position as soon as it is available.

Issue Paper

BONNEVILLE POWER ADMINISTRATION'S
RESPONSE TO THE
NORTHWEST POWER PLANNING COUNCIL'S
TWO-YEAR ACTION PLAN — PRELIMINARY STAFF ANALYSIS

INTRODUCTION

The Northwest Power Planning Council's twenty-year plan for meeting the Region's electrical energy needs includes a variety of activities for the Bonneville Power Administration to undertake during the next two years. These activities are described in the two-year action plan (Chapter 10). The two-year action plan is designed to enable BPA to acquire the most cost-effective resources throughout the full twenty years of the plan. This includes the ability to meet rapid economic growth with the least costly resources available. The plan explains the objectives in this way:

> The Council has concluded that this two-year plan should focus on enhancing the region's capability to (a) implement conservation, (b) develop smaller, more dispersed renewable resources, and (c) shorten the lead time for the siting, licensing, and construction of generating plants. To accomplish those goals, Bonneville must support programs to acquire cost-effective conservation from all major consumer groups (residential, commercial, governmental, industrial, and agricultural). While the rate of conservation acquisitions must reflect the need for power in the region, the development of the capability to acquire conservation cannot wait. Bonneville must be ready to respond on short notice with conservation programs and resources if power demands increase. Currently, Bonneville and the region's utilities have limited capability to implement conservation programs outside the residential sector. Bonneville must also begin developing resource options. This includes completing the planning and regulatory activities on certain resources and providing services to facilitate the early development of resources that might otherwise be lost to the region, such as cogeneration. Finally, Bonneville must

> conduct research, development, and demonstration projects to imporve the information on which future resource decisons will be made.
>
> * * *
>
> These actions are designed to maintain or improve Bonneville's ability to acquire conservation and other resources when they are needed. Because of the current surplus of power, this two-year plan does not include the acquisition of any conservation or other resources solely for the purpose of acquiring power.
>
> * * *
>
> The Council has determined that the actions in this two-year plan are cost-effective, prudent, and necessary for Bonneville to acquire the lowest cost resources consistent with the priorities, considerations, and other requirements of the Northwest Power Act.

On August 15, 1983 Bonneville published its response to the Council's request for a work plan and schedule for carrying out its responsibilities under the plan. This issue paper provides the Council staff's preliminary analysis of Bonneville's response to the Council plan. It seeks to answer five questions.

1. Has BPA committed to act consistent with the Council's plan?
2. Are there any significant differences between what the plan provides and what BPA has committed to accomplish?
3. If significant differences exist between the Council's plan and Bonneville's intended actions, what reasons does Bonneville give for not acting consistent with the plan?
4. Will Bonneville's desired variances from the plan jeopardize the achievement of either the two-year action plan's goal of capability building in all sectors and/or the plan's long-term goal of securing a least cost resource mix?
5. What should the Council and Bonneville do to resolve inconsistencies between the plan and BPA's proposed FY 84/FY 85 activities.

The preliminary conclusions of the staff are that 1) BPA has committed to act consistently with the Council's plan (with three specified reservations),

2) the response on the conservation program contains significant differences from the plan and may not be consistent with BPA's commitment, and 3) the response on other resource actions varies from the plan in some respects but appears to be consistent with BPA's commitment. The staff recommends a process to identify precisely any disagreements on the conservation program and to resolve as many disagreements as can be resolved.

ANALYSIS

Has Bonneville committed to act consistent with the Council's plan?

The introduction to Bonneville's response to the Council expresses a commitment to follow the plan. It states: "Pure and simple, BPA intends to be guided by the Council's Plan." In addition, BPA's Administrator Peter Johnson in his letter transmitting the agency's work plan and schedule indicated that "BPA fully supports all of the objectives of the Council's two-year action plan." The Administrator also states that BPA's "resource acquisition (including conservation) will be consistent with the plan as provided by law."

Bonneville further indicated that where there may be serious disagreements over specific action items it will consult with the Council to seek "appropriate and mutually acceptable solutions." Finally, BPA states that,

> In areas where BPA and the Council disagree over the appropriateness of implementing a particular action item and where it is one party's opinion against the other's, where mutually acceptable resolution is not reached and where there are no legal constraints, financial or budgetary limitations of the U.S. govenrment, or breaches of prudent utility practice confronting BPA, the Council's approach will be followed (emphasis added).

In sum, BPA has committed to follow the Council's plan while reserving three reasons for taking actions inconsistent with the plan. Unless a Council action is illegal, financially impossible or imprudent, BPA has pledged to act consistently with the plan.

Are there any significant differences between what the plan directs BPA to do and what the agency has committed to accomplish?

Bonneville's response to the plan in the areas of conservation and generating resources reflects a general agreement between the agency and the Council. However, there are significant differences between the plan and what Bonneville has committed to accomplish during the next two years. These differences can be divided into two general categories.[1] The first category (BPA's Category IB) includes 74 actions in the Council's plan for which BPA cannot assure funding due to limitations imposed upon BPA borrowing from the U.S. Treasury and reduced expectations of the amount of financing available to BPA from non-federal sources. Absent this funding uncertainty BPA would commit to accomplishing these action items. The Council is already on record stating that it will work with Congress and the Administration to help secure additional borrowing authority from the Treasury.

The second category (BPA's category II) includes 14 of the plan's two-year action items which BPA feels have serious implementation problems. Bonneville has indicated that it cannot commit to accomplishing the following actions "as specified":

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[1] BPA has classified the Council's action items into three categories. These are:

Category IA:	"Want to do and can do" (27 items)
Category IB:	"Want to do, and will try to do, but cannot assure" (74 items)
Category II:	"Can't do as specified; need to consult with Council." (14 items)

Residential Sector

1.F Discontinue the residential water heater wrap program

2.8 Develop and implement a program which secures a 25 percent market penetration of the Council's model standards for new residential construction between 1984-1986

2.9 Provide incentive payments of 4.0 cents per kilowatt hour for energy saved in new residential construction in areas which adopt the model standard prior to 1986

4.D Offer financial incentives to reduce the number of older, less-efficient refrigerators and freezers

4.1 Develop and implement an applicance efficiency demonstration program which acquires 2 megawatts by January 1, 1986

Commercial Sector

5.1 Develop and implement a commercial sector conservation program which acquires 20 megawatts by January 1, 1986

6.7 Develop and implement a program which secures 15 megawatts of savings in new commercial buildings built prior to 1986

6.8 Provide incentive payments of 4.0 cents per kilowatt hour for energy saved in new commercial structures in areas which adopt the model standard prior to 1986

Agricultural Sector

10.E Provide incentive payments to defray the incremental captial cost of installing efficient irrigation systems

10.1 Develop and implement an agricultural sector conservation program which acquires 15 megawatts by January 1, 1986

Industrial Sector

9.1 Develop and implement an industrial sector conservation program which acquires 15 megawatts by January 1, 1986

Governmental Sector

12.13 Terminate the Street and Area Lighting program

Generating Resources

19.1 Acquire an existing natural gas combustion turbine and petition for exemption from the Fuel Use Act

20.1 Assist potential cogenerators obtain access to tielines which enable them to market cogenerated electricity not currently needed by the region

Although BPA states that it cannot accomplish these 14 action items "as specified," it has suggested alternative approaches to accomplishing each item's objective.

Attachment I summarizes the nature of BPA's commitment by Council action item. In aggregate this table reveals that Bonneville cannot assure the achievement of any conservation action item in the non-residential sector except consultation with state and local governments. Moreover, even absent borrowing limitations, BPA has indicated that it does not feel that it is necessary to achieve the Council's acquisition targets in any sector except residential. Only conservation action items which represent ongoing BPA programs appear in the "Want to do, and can do" category (Category IA). All others are classified as "cannot assure" or "cannot do as specified" (Categories IB and II).

Table I shows that during the next two fiscal years Bonneville intends to develop, either through direct acquisiton or pilot programs, a total of 115 megawatts of conservation savings compared to the 150 megawatt target set forth in the Council's Plan.[2] Of this 115 megawatts, 76 percent would be obtained from the residential sector, 11 percent from the commercial sector, 2 percent from industrial savings, 9 percent from governmental sector programs, and 2 percent from irrigated agriculture. As can be seen by comparing Bonneville's planned savings with the Council's targets this

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[2] Although BPA states in its August 15, 1983 response to the Council and in its public information literature that it would acquire 155 megawatts (excluding pilot programs), this figure includes 56 megawatts of savings that will have been developed prior to FY 1984.

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Table 1

Summary of Council and Bonneville Conservation Targets by Sector and Program for FY 1984/85

Sector	Council Acquisition Target		BPA Planned Savings			
	MW	%	Acquisition	Pilot*	Total MW	Total %
Residential						
Existing Buildings	65		64	3	67	
New Building Standards	5		0	2	2	
Water Heat	3		16**	2	18	
Other Appliances	2		0	1	1	
Sector Total	75	50	80	8	88	76
Commercial						
Existing Buildings	20		8	4	12	
New Buildings	15		0	1	1	
Sector Total	35	25	8	5	13	11
Industrial	15	10	1	1	2	2
Agriculture	15	10	0	2	2	2
Government	10	5	10	0	10	9
Total	150	100%	99	16	115	100%

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*Pilot program savings are approximate.

**Savings from water heater wraps installed when house is retrofitted.

distribution clearly is at variance with the Councils expressed desire to diversify BPA's conservation program. Thus, while BPA has made a general commitment to follow the Council's plan there are significant differences between what Bonneville has stated it is specifically able (or willing) to accomplish and what is called for in the plan.

If significant differences exist between the Council's plan and BPA's intended actions, what reasons does the agency give for not acting consistent with the plan?

Bonneville has not committed to accomplishing 88 of the 115 actions called for in the Council's plan. Bonneville in its work plan has assured the Council that it can accomplish 27 action items within its present Treasury borrowing limit of $121 million. These items include research and development projects which are directly expensed into rates and those programs which are contractually obligated, such as residential weatherization, street and area lighting and the Hood River Project. However, the agency indicates that unless it is able to secure an additional $50 million in conservation borrowing authority for FY 84 it cannot commit to accomplishing 74 additional action items. Failure to obtain access to this additional Treasury borrowing will necessitate a change in BPA implementation schedules and reordering of priorities.

In addition to 74 conservation action items which BPA has not committed to accomplish due to Treasury borrowing limitations, there are 14 other action items which the agency states it cannot accomplish "as specified." In Bonneville's judgment the attainment of six of these 14 items would exacerbate current rate increases and aggravate the present power surplus. This assertion is contrary to the finding expressed by the Council in its plan regarding the need to balance near term resoruce and rate impacts and capability building. These six action items, Bonneville's estimated cost of accomplishing them and the Council's acquisition target associated with each appear in Table 2.

As shown in Table 2, Bonneville estimates that in order to accomplish the conservation targets specified in these actions it would have to expend an additional $133 to $163 million during FY 84/FY 85.[3] BPA's current budget for conservation for fiscal years 1984 and 1985 is about $422 million. Adding Bonneville's estimated cost of accomplishing the above conservation action items would raise its FY 84/FY 85 budget level to between $555 and $585 million. The Council's own estimate of the cost of its two-year action plan is $479 million. Thus, BPA's cost estimate is approximately 16 to 22 percent higher than the Council's. The majority of this difference appears to be attributable to expenditures in the residential sector that exceed levels called for in the plan.

Based on the staff's analysis, if BPA increased its budget by the amount the agency estimates would be necessary to accomplish all of the Council's two-year conservation action items, and assuming this additional investment were debt financed there would be no perceptible effect on 1985 retail rates. Even under a "worst case" set of financing assumptions (i.e., BPA expenses $50 million per year to fund category IB action items in its curret budget, plus an additional $130 million for the Category II Council action items) 1985 retail rates would increase by less than 10 percent. Attachment 2 discusses the staff's rate impact analysis in more detail.

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[3] Although this is the total reported in Bonneville's written response, more recent correspondence with BPA staff indicates that the range shown may be $60 million too low.

Table 2

Council Action Items Which BPA Indicates Cannot Be Accomplished "As Specified" Due To Rate and Resources Impacts

Action Item		BPA's Estimated Cost Millions	Megawatts
2.8	Twenty-five percent market penetration of model standard in new residential construction	$50-$80	5
4.1	Residential appliance efficiency demonstration program	$ 4	2
5.1	Commercial sector aqcuisition program	$ 30	20
9.1	Industrial sector acquisition	$ 23	15
10.1	Agricultural sector acquisition program	$ 26	15
19.1	Combustion turbine acquisition and Fuel Use Act exemption	$4-50	N.A.
	Total conservation action items only	$133-163	57
	TOTAL	$137-213	

BPA also states that it "cannot do as specified" eight other action items because, in the agency's judgment, the Council's approach to achieving these items is either infeasible/impractical or in conflict with other Bonneville obligations/policies. These eight action items and Bonneville's rationale for not committing to accomplishing them "as specified" are described in Table 3. Staff comments on BPA's response are also provided.

Will Bonneville's desired variances from the plan jeopardize the achievement of either the two-year action plan's goal of capability building in all sectors and/or the plan's long term goal of securing a least cost resource mix?

The long term goal of the Council's plan is to be able to meet the electricity demand of a high growth economy with the cheapest resources available. In order to accomplish this goal the basic thrust of Council's two-year action plan is "to build the capability of the Region's conservation delivery system to ensure that, as the current power surplus diminishes, Bonneville, utilities, state and local governments and the private sector will be abe to acquire cost-effective conservation at a pace sufficient to meet the Council's long term conservation targets." Bonneville indicates that it does not disagree with the fundamental near term objective of the Council's plan of regional capability building. However, as discussed in the previous section there are significant differences between what BPA has commited to accomplish and the Council's two-year action plan. Do these differences jeopardize achievement of the plan's goals? More specifically, will the actions BPA proposes to undertake in lieu of those set forth in the Council's plan produce comparable results without incurring the cost associated with near-term acquisitions and aggravating the current power surplus?

Table 3

Council Action Items Which BPA Indicates Cannot Be Accomplished "As Specified"

	Action Item	Bonneville Response
1.F	Discontinue residential water heat wrap program	Include water heater wraps in residential weatherization program. Comment: Consistent with Council's intent as specified in Action items 1.A and 1.C.
4.D	Old appliance trade-in incentives	Would not result in deficit period savings; may be more efficient to assess effectiveness of other similar programs outside of region via literature review. Cost estimated at $600,000. Comment: Literature review would not develop regional capability. Further clarification required.
10.E	Incentive payments for installation of efficient irrigation systems on new lands. Failure to install all cost-effective measures renders farmer ineligible for retrofit incentives.	Incentive payments are unnecessary due to cost-effectiveness of efficient systems. Comment: The Council's analysis of the economic attractiveness of efficient irrigation systems agrees with BPA. However, financial incentives may still be necessary to defray the incremental cost of some systems. BPA's intent to institute a policy of not allowing systems installed on new acreage to qualify for retrofit incentives needs further clarification.
12.13	Terminate Street and Area Lighting Program	Contrary to Council's impression savings will continue after surplus ends. Program provides opportunity for contractors (utilities, local governments) to develop administrative capability. Comment: Program appears justified unless it jeopardizes implementation of new programs in other areas which have larger total savings potential and for which no administrative capability has yet been developed. Need further clarification of program intent.

Action Item	Bonneville Response
2.9 Model standards early adoption incentive of 4 cents per kilowatt hour for residential consumers	Payment is too small to be administerd and may not be sufficient to encourage early adoption. Technical problems exist in calculating actual savings. Estimated cost $7.5 million. Comment: BPA administered its water heater wrap program which delivered a $32/wrap payment. Early adoption incentives would range between $200-$350/year/unit. Incentive are calculated based on estimated savings over present codes just as are retrofit payments. In some cases early adoption incentive is necessary to ensure standard's economic feasibility since standards were based on average retail rates as of 1986. Cost appears to include double counting in order to achieve 25 percent market penetration. Need to consult on program design.
6.7 Model standards incentive for commercial buidlings and 6.8 Model standards early adoption incentive (4 cents per kilowatt hour).	Large savings would be difficult to demonstrate since commercial sector standard is not particularly stringent compared to current practice. Normal lead times for commercial buildings construction make it unlikely that significant savings could be achieved by January 1, 1986. Estimated cost $48 million. Comment: Model standard for new commercial building will have major impact on small to moderate sized commercial buildings which typically do not have long lead times for construction. Many areas of region do not have commercial code. Lighting standard will produce significant savings in large office and retail structures because it is the most stirigent in country. BPA cost estimate appears to assume that it pays both early adoption incentive and incremental cost. Need to consult on program design.
20.1 Assist potential cogenerators gain intertie access.	BPA is developing intertie access policy. BPA interprets Council action item to give cogenerators priority access on intertie. Comment: Clarify Council's intent.

There are three primary reasons for believing that BPA's implementation program may jeopardize the development of the regional capability to deliver conservation. First, the total conservation acquisitions planned by BPA for FY 84/FY 85 is 99 megawatts (excluding pilot programs). This is only two-thirds of the Council's two year acquisiton target of 150 megawatts. The Council established its two-year conservation acquisition target to ensure that sufficient resources would be available to accommodate a high rate of economic growth. The near-term targets for each sector were set based on amount of power required in future years and the maximum rate of market penetration that might reasonably be achieved in any one year and from one year to the next. Since Bonneville's own "least cost mix analysis" arrived at very similar results (identifying 140 megawatts as 1985 a target), their failure to commit to achieving the Council's target is of obvious concern.

Secondly, in addition to the absolute difference between the Council's and BPA's total conservation target there are significant differences in distribution of the savings among the major sectors. The Council's plan calls for Bonneville to diversify its conservation acquisition programs. Yet, as noted previously, BPA intends to secure only 24 percent of its savings from the non-residential sectors during the coming two fiscal years. In contrast, the Council's acquisition targets for the non-residential sectors represented 50 percent of its resource portfolio during these same years. Table 4 summarizes BPA's proposed FY 84/85 conservation expenditure by sector. As is the case with BPA acquisition targets, expenditures for both acquisitions and non-acquisitons (i.e., pilot programs) in the residential sector dominate the agency's conservation budget.

Finally, while the attainment of quantitative conservation targets are an essential measure of program achievement, they are not the only attribute defining "regional capability." Developing the region's capability to accomplish the Council's long-run conservation targets requires the completion of several equally critical tasks. These include, among other things, securing

Table 4

BPA Conservation Budget For Fiscal Year 1984 and 1985*

(millions of dollars)

Sector	Acquisition	%	Non-Acquisition	%	Total	%
Residential	$ 244.6	85	$ 21.5	16	$266.1	63
Commercial	17.7	6	30.1	22	47.8	11
Industrial	8.5	3	1.8	1	10.3	3
Irrigated Agriculture	0	0	5.1	4	5.1	1
Governmental	15.5	6	16.0	12	31.5	7
Program Support	0	0	61.1	45	61.1	15
TOTAL	$ 286.3	100%	$ 135.6	100%	$421.9	100%

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*Cost include BPA overhead.

credible cost and performance data; establishing an efficient and effective administrative system; training the labor force that will design, install and provide quality assurance; and, developing quality control tools, procedures and materials specifications. Even BPA acknowledges that its pilot programs "operate under different contracts than acquisition programs and therefore do not provide either regionwide operating or comparable administrative experience". Consequently, it is doubtful that pilot programs alone, unless very carefully designed, will result in the development of sufficient regional capability to attain the Council's long-run conservation targets.

How should the Council and BPA resolve differences between the plan and Bonneville's proposed work program?

Based on its preliminary analysis of Bonneville's work program and BPA's specific request to consult with the Council on areas where there are differences between the plan and the agency's proposed actions the staff recommends the following:

1. Direct Council staff to consult with BPA to identify those two-year action items on which there is agreement that Bonneville's work plan is adequate and those action items on which there is disagreement over the adequacy of Bonneville's response.
2. Present the results of this staff consultation to the Council at the Council's first meeting in October.
3. Issue a document for public review and comment which clasifies two-year action items into three areas:
    a. Actions where BPA implementation program is consistent with the plan. In some cases the Council would clarify the intent of the action item, or make determination of consistency.
    b. Actions where the Council proposes amendments to the plan to incorporate BPA implementation programs that accomplish the same objective.
    c. Actions where BPA's implementation programs are inconsistent with the plan and further Council action is required.

The Council will make every effort to ensure public involvement and participation during this process. Should an amendment to the plan be necessary, the Council will hold public hearings in each of the affected states, as prescribed by the Act.

Daniel J. Evans
Chairman
Washington

Charles Collins
Washington

Keith Colbo
Montana

Gerald Mueller
Montana

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Vice-Chairman
Idaho

W. Larry Mills
Idaho

Alfred A. Hampson
Oregon

Roy Hemmingway
Oregon

October 14, 1983

Mr. Richard L. Durham
Special Assistant to Administrator
for Conservation
Bonneville Power Administration-K
P. O. Box 3621
Portland, Oregon 97208

Dear Dick:

As a follow-up to our meeting with you, Bob Lewis, Kirk Hall, Syd Berwager, and others on October 12, I thought it would be helpful to describe more specifically what the Council staff envisions as BPA's final product. As we discussed, the Council wants to complete the staff-to-staff consultations regarding "work statement development" prior to Thanksgiving. To enable Council staff to prepare a status report on BPA's workplan for the first Council meeting in December, we will need BPA's final statement of work by November 15.

We expect that BPA's final submission to the Council will include the following for each action item:

1) A comprehensive statement of work which describes the major tasks that will be undertaken, and how they are interrelated.

2) A schedule of work which indicates critical milestones.

3) The level of effort anticipated for each task, i.e., FTE's, budget for outside contractor assistance, and total budget.

4) A description of the major interim and final deliverables anticipated.

5) The name of the person responsible for managing the completion of each action item. For external purposes, the name of the appropriate Division Director or Branch Chief will be adequate. However, to facilitate staff-to-staff communications, we need to know the appropriate program managers to contact.

It's my understanding that Kirk Hall will be providing a draft version of the work statement for those action items dealing with at least the commercial sector capability building acquisition programs on October 21 for our review. I hope this outline of our needs is useful in the preparation of that response.

Sincerely,

Ed

Edward Sheets
Executive Director

JOHN V EVANS
GOVERNOR

BOB SAXVIK
VICE CHAIRMAN

[redacted]

W. LARRY MILLS
COUNCIL MEMBER

OFFICE OF THE GOVERNOR

September 20, 1983

The Honorable David Stockman, Director
Office of Management and Budget
Old Executive Building
17th and Pennsylvania Avenue N.W.
Washington, D.C. 20500

Dear Mr. Stockman:

I am writing on behalf of the Northwest Power Planning Council to urge the administration to ensure that the Bonneville Power Administration is given adequate financial capability to acquire resources by borrowing from the United States Treasury as authorized by the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (P.L. 96-501, 16 U.S.C. 839 et seq.). The resources to be acquired by the Bonneville Power Administration are specified in the Council's Northwest Conservation and Electric Power Plan adopted pursuant to that Act (P.L. 96-501).

That Act established the Northwest Power Planning Council to guide the resource acquisition activities of the Bonneville Power Administration. The Council is a regional compact agency made up of eight members, two each from the states of Idaho, Montana, Oregon and Washington. Council members are appointed by their governors and confirmed by their legislatures.

Congress directed the Council to determine the electrical energy needs of the Pacific Northwest and develop a plan to meet those needs. The Council completed its first regional plan by the deadline set by the Congress (a copy is enclosed for your information). The Plan is designed to be able to sustain a strong, growing economy in the Pacific Northwest using the lowest cost resources.

The Council is concerned that the region's ability to meet its power needs, as intended by Congress, will be much more difficult without proper financing. Bonneville has informed the Council that it cannot assure the implementation of 74 of the 115 actions

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that the Council believes are necessary to meet the region's power needs because of financing uncertainties. In addition, the Council and Bonneville are currently consulting on the best way to demonstrate the capability to implement conservation programs in the commercial, industrial and agricultural sectors. Depending on the outcome of these discussions, additional financing may be needed.

There are two alternatives for financing the Council's least cost resource programs for the Northwest. The first involves conventional borrowing by the utilities in the region. The second was authorized by Congress in Section 8(d)(3) of the Pacific Northwest Electric Power Planning and Conservation Act which created a $1.25 billion revolving fund for the purpose of providing funds for conservation and renewable resources. The revolving fund is repaid with interest by Bonneville's ratepayers, not by U.S. taxpayers. Bonneville's current rate case assumed that for FY 84, the region's utilities would borrow approximately $58 million from private sources and Bonneville would borrow $121 million from the Treasury to fund Bonneville conservation programs.

The default on the outstanding bonds for Washington Public Power Supply System plants 4 and 5 by 88 Northwest utilities renders most Northwest utilities unable to borrow money in the near future. As a result, we believe that Bonneville should have sufficient flexibility to exercise its U.S. Treasury borrowing under the existing authority created by Section 8(d)(3) of the Act. The Council believes that this borrowing flexibility is critical to the region's ability to meet its power needs.

This letter is also being sent to Donald T. Regan, Secretary of the Treasury, and Donald P. Hodel, Secretary of Energy. A similar letter is being sent to each member of the Northwest Congressional delegation.

Sincerely,

Bob Saxvik

Robert W. (Bob) Saxvik
Acting Chairman

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Idaho

Alfred A. Hampson
Oregon

Roy Hemmingway
Oregon

September 21, 1983

The Honorable James A. McClure
United States Senate
Washington, D.C. 20510

Dear Senator McClure:

I am writing on behalf of the Northwest Power Planning Council to inform you that the Council has written the administration to urge that the Bonneville Power Administration be given adequate financial capability to acquire conservation and renewable resources by borrowing from the United States Treasury as authorized by the Pacific Northwest Power Planning and Conservation Act of 1980 (P.L. 96-501). The conservation and renewable resources to be acquired by the Bonneville Power Administration are specified in the Council's Northwest Conservation and Electric Power Plan adopted pursuant to that Act.

That Act established the Northwest Power Planning Council to guide the resource acquisition activities of the Bonneville Power Administration. The Council is a regional compact agency made up of eight members, two each from the states of Idaho, Montana, Oregon and Washington. Council members are appointed by their governors and confirmed by their legislatures.

Congress directed the Council to determine the electrical energy needs of the Pacific Northwest and develop a plan to meet those needs. The Council completed its first regional plan by the deadline set by the Congress. The Plan is designed to be able to sustain a strong, growing economy in the Pacific Northwest using the lowest cost resources.

The Council is concerned that the implementation of the regional plan, as intended by Congress, will be made much more difficult if not properly financed. Bonneville has informed the Council that it cannot assure the implementation of 74 of the 96 conservation actions contained in the Council's Plan because of financing uncertainties. In addition, the Council and Bonneville are currently consulting on the best way to demonstrate the capability to implement conservation programs in the commercial, industrial and agricultural sectors. Depending on the outcome of these discussions, additional financing may be needed.

There are two alternatives for financing conservation and other resource programs in the Northwest. The first involves conventional borrowing by the utilities in the region. The second was authorized by Congress in Section 8(d)(3) of the Pacific Northwest Electric Power Planning and Conservation Act which created a $1.25 billion revolving fund for the purpose of providing funds for conservation and renewable resources. The revolving fund is repaid with interest by Bonneville's ratepayers, not by U.S. taxpayers. Bonneville's current rate case assumed that for FY 84, the regions' utilities would borrow approximately $58 million from private sources and Bonneville would borrow $121 million from the Treasury to fund Bonneville conservation programs.

The default on the outstanding bonds for Washington Public Power Supply System plants 4 and 5 by 88 utilities renders most Northwest utilities unable to borrow money in the near future. As a result, we believe that Bonneville should have sufficient flexibility to exercise its U.S. Treasury borrowing for conservation program expenditures under the existing authority created by Section 8(d)(3) of the Act.

The Council believes that this borrowing flexibility is critical to the successful implementation of the regional power plan and the region's ability to meet its power needs.

A similar letter has been sent to Mr. David Stockman, Director of the Office of Management and Budget.

Sincerely,

Robert W. (Bob) Saxvik
Acting Chairman

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May 17, 1983

MEMORANDUM

TO: COUNCIL MEMBERS

FROM: Edward Sheets ES

SUBJECT: BPA Long-Term Conservation Contracts

Bonneville has recently completed the negotiation of the contractual language for the general contract provisions of its long-term conservation contracts. In addition, BPA has also completed negotiation of its street and area lighting and weatherization programs. BPA intends to offer the contracts for its street and area lighting and weatherization programs to utilities and other entities in June or July. The public comment period on the proposed final language closes May 18, 1983. The staff has identified several areas in these contracts which appear to be inconsistent with the policies and principles expressed in the Council's plan. These are discussed below.

Weatherization Program Contract Provisions

1) Low-income definition - BPA has defined low income (i.e., those eligible for full cost reimbursement) as "at or below 125 per cent. of the poverty level." Section 1(g). The Council's plan defines low income as "at or below 70% of the median city or county household income" (Two-Year Action 1E). BPA's definition would reduce the number of households eligible for full cost reimbursement.

2) Conditions for receiving financial assistance - The Council's plan requires, as a condition of receiving BPA financial assistance, the installation of all structurally feasible and regionally cost-effective measures. BPA's contracts do not contain an equivalent provision.

3) Level of Reimbursement - BPA's new contract would limit consumer incentives for weatherization to the actual cost of the measures or to 85% of 29.2c/kwh if the consumer agrees to adopt all cost-effective measures and 75% of 29.2c/kwh if the consumer does not adopt all cost-effective measures, whichever is less. Low income consumers would receive full cost reimbursement up to 29.2c/kwh (Exhibit E).

The Council's plan directs BPA to provide financial assistance at levels not lower than BPA's current program. The plan also directs BPA to provide reimbursement for the weatherization of houses occupied by low income consumers at a level not to exceed 4.0¢/kwh. BPA's proposed limit is equivalent to approximately 1.7c/kwh.

4) Proportionate service to low income and renters - There are no provisions in BPA's proposed contracts which direct utilities and/or other weatherization program operators to secure program participation rates among low income and renter-occupied households. This is inconsistent with the Council's Two-Year Action 1D.

Street and Area Lighting Program Contract Provisions

The Council's plan directs BPA to terminate its street and area lighting program. BPA's present contract provides for the maintenance of the program at substantially reduced funding levels. Measures included in the program are assumed to have a 20-year life. This appears to be inconsistent with Council's intent to eliminate those measures which are expected to produce savings only during the period of surplus.

General Contract Provisions

Based on a preliminary analysis by the Power Planning Division, there does not appear to be any direct conflict between BPA's proposed general contract provisions and the Council's plan. However, many of the parties to the negotiation process have serious reservations regarding the recovery of a portion of the conservation cost through the use of a contract charge as well as rates. The staff has not prepared an analysis of this issue.

A copy of my letter to BPA officially placing the plan in Bonneville public comment record is attached.

AVAILABLE

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Alfred A. Hampson
Oregon

Roy Hemmingway
Oregon

May 17, 1983

Ms. Donna L. Geiger
Public Involvement Manager
Bonneville Power Administration
P.O. Box 12999, ALP
Portland, Oregon 97212

Dear Ms. Geiger:

As you are aware, the Northwest Power Planning Council adopted its Northwest Conservation and Electric Power Plan on April 27. The Plan includes in the Two-Year Action Plan (Chapter 10) specific actions for BPA's conservation and resource acquisition programs. A copy of the Plan is enclosed.

Our preliminary staff review of BPA's proposed long-term conservation contract provisions reveals several areas where the contract appears to be inconsistent with the Plan. These are as follows:

1. BPA's definition of low-income (Section 1(g)) differs from the Council's Two-Year Action 1E.
2. The limit on the level of cost reimbursement (Exhibit 1), when applied to low-income households, is set below the level in the Plan (Two-Year Action 1E).
3. The consumer incentive provided (Exhibit E2 and 3) for households that do not qualify as low-income is set below current BPA incentive levels (Two-Year Action 1D).
4. There is no requirement that a consumer must install structurally feasible and regionally cost-effective measures as a condition of receiving BPA financial assistance (Two-Year Action 1C).
5. There is no requirement that market penetration rates for low-income and tenant-occupied structures be at least proportionate to their respective shares of all electrically-heated households in a reasonably defined geographic area (Two-Year Action 1D).

I understand that BPA is seeking comments on the proposed conservation contracts by May 18. Please consider the attached plan as the Council's formal comments on the proposed conservation contracts. In the Plan, the Council states that:

> "Section 4(d)(2) of the Act provides that all conservation and resource acquisitions by Bonneville 'shall' be consistent with this plan, except as otherwise specifically provided in the Act. Section 6 of the Act, dealing with Bonneville resource acquisitions, states:
>
> (b)(1) Except as specifically provided in this section, acquisition of resources under this Act shall be consistent with the plan, as determined by the Administrator.
>
> (2) The Administrator may require resources (other than major resources) under this Act which are not consistent with the plan, but which are determined by the Administrator to be consistent with the criteria of section 4(e)(1) and the considerations of section 4(e)(2) of this Act.
>
> Any major resource acquisition is subject to review by the Council and a Council determination of consistency or inconsistency with this plan. A major resource is a resource with a planned capability greater than 50 average megawatts that is acquired for a period of more than five years.
>
> The Council has used the word 'shall' in this two-year action plan, when referring to actions to be carried out by Bonneville, to express the Council's expectation that these actions can and should be implemented. It is the sense of the Council that these actions must be taken now for Bonneville to be able to acquire the lowest cost mix of resources over the next twenty years. The Council will consider Bonneville's record in implementing these actions as a part of any Council proceedings under section 6(c)(2) of the Act, regarding the consistency of major resource proposals with this plan."

We would be pleased to consult with the BPA staff on the terms of the Council's Plan and their application to BPA's conservation contracts, if that would be useful.

Sincerely,

Edward Sheets

Edward Sheets
Executive Director

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

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AUG 1 9 1983

Mr. Ed Sheets
Executive Director
Northwest Power Planning Council
700 S.W. Taylor Street, Suite 200
Portland, Oregon 97205

Dear Ed:

This is to provide you with a status report on the Bonneville Power Administration's determinations and commitments in regard to the issues raised in your letter of May 27, 1983.

Bonneville does not intend to withdraw the new Weatherization Program replacement contract, nor does it intend to extend the existing Energy Conservation Agreement beyond the expiration date of September 30, 1983. Bonneville will negotiate, pursuant to Section 23 of the General Conservation Contract Provisions (GCCP), such amendments to the Weatherization Program as are necessary to insure successful implementation of the Council Plan.

In relation to the five numbered points of your letter, the following actions are under consideration:

1. BPA's definition of low-income (Section 1(g)) differs from the Council's Two-Year Action 1E.

Modification of the definition of low-income households will be implemented as part of the amendment process, following the establishment of active low-income programs under the replacement contracts.

2. The limit on the level of cost reimbursement (Exhibit 1) when applied to low-income households, is set below the level in the Plan (Two-Year Action 1E).

Change will be made here when item 4 is instituted. The offered contract, meanwhile, allows low-income persons to select measures so as to assure 100 percent financing.

3. The consumer incentive provided (Exhibit E2 and 3) for households that do not qualify as low-income is set below current BPA incentive levels (Two-Year Action 1D).

The offered program does not operate below current BPA levels for homes choosing all measures. The incentive structure is intended to act as an incentive for homeowners to select all measures while preserving consumer choice and respecting the varied requirements of public utility commissions and utility governing boards. It also will accomplish an important cost and quality control objective and will remove a regional east-side/west-side inequity in cost coverage of the available incentive payments.

4. There is no requirement that a consumer must install (all) structurally feasible and regionally cost-effective measures as a condition of receiving BPA financial assistance (Two-Year Action 1C).

Bonneville shares its contractors' concerns about the potential for consumer confusion and administrative difficulties related to changing the current payment program to the proposed 85/75 percent split, and then changing the program again to meet the all-or-nothing recommendation of the Council Plan. Therefore, Bonneville has modified the replacement agreement to retain substantially the existing incentive payment system until amendments to implement the Council objective in this item can be completed and the program changes made operational.

5. There is no requirement that market penetration rates for low-income and tenant-occupied structures be at least proportionate to their respective shares of all electrically-heated households in a reasonably defined geographic area (Two-Year Action 1D).

Bonneville will achieve this objective through its system of budgeting and program controls, not through specific contract terms. Bonneville will allocate a percentage of the FY 1984 budget to low-income weatherization. Reviews of the submitted budgets and the capability of operators to institute low-income programs will determine actual program goals for the fiscal year. Contractors will be held to the performance criteria in the contract in the operation of low-income programs. Bonneville intends to have a program operating regionwide at the levels implied in item 1 by FY 1985.

Bonneville has an incomplete capability in the rental sector. The current program can operate only with structures that are of wood frame construction or no more than three floors above grade. Development of capability to do larger structures will be dependent upon the success of the Commercial Audit and Commercial Financial Incentives Programs currently under design. To initiate a rental program, Bonneville will determine, in conjunction with its contractors, the size of the rental sector in each contractor's service territory by housing type. Bonneville will subsequently initiate a control system similar to its low-income approach in order to assure appropriate program penetration rates among renters.

Our contract amendment process for weatherization items will likely involve the following steps:

1. Creation of a task group composed of representatives from the States, utilities, and BPA - August 1983.
2. Program development discussions in the task group - August-November 1983.
3. Formal negotiation with contractors - November 1983.
4. BPA internal clearance - December 1983.
5. Contract amendment offering - January 1984.
6. Contractor execution of amendment - May 1984 (120 days from date of offer).

The primary work of the task group will be in identifying, for purposes of negotiation by the parties, the options, and implementation steps associated with them, that would accomplish the subject action items.

This process is consistent with the Administrator's letter covering the long-term conservation contract offerings and reaffirms Bonneville's commitment to implement the Plan.

If you have any questions, please feel free to call me.

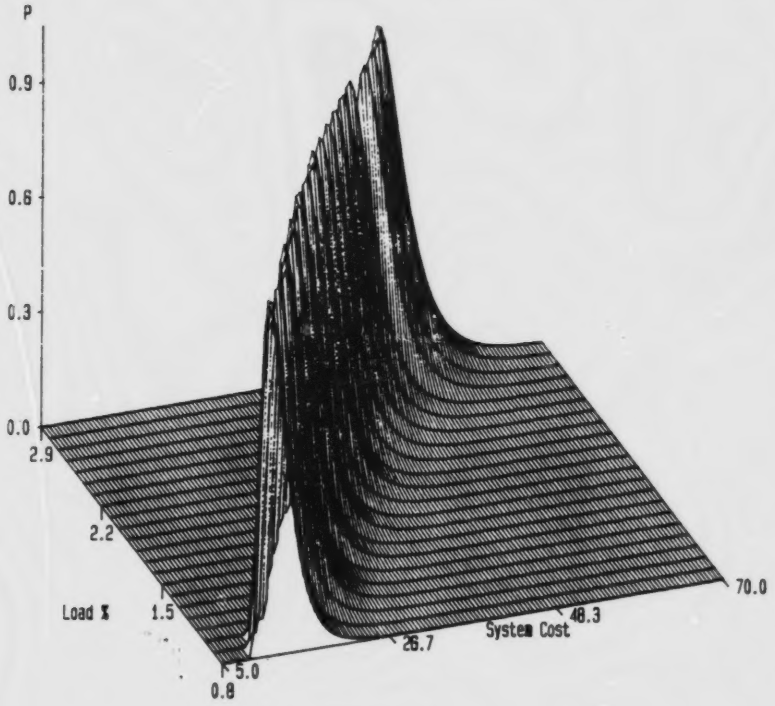
Sincerely,

Steven G. Hickok
Assistant Administrator for Conservation

NORTHWEST POWER PLANNING COUNCIL

WPPSS 1, 2, & 3
DECISIONS UNDER UNCERTAINTY

Draft Issue Paper



October 26, 1983

Staff Issue Paper
WPPSS COST-EFFECTIVENESS ANALYSIS
DECISIONS UNDER UNCERTAINTY
October 26, 1983

I. INTRODUCTION

The three remaining WPPSS plants were grandfathered by the Northwest Power Act that authorized the creation of the Council. The Council therefore assumed WNP 1, 2, and 3 were part of the existing power system when it developed its regional power plan. The energy from WNP 1, 2, and 3 was assumed to be available based on the official plant schedule in existence last spring. With BPA's decision to mothball WNP 3 and proposed Congressional legislation to provide a financing mechanism to continue the plant's construction, the need and cost-effectiveness of the three remaining Supply System plants came into question.

In August, the Council directed its staff to undertake studies of the cost-effectiveness and need for WNP 1, 2, and 3. The Council staff provided status reports on its work to the Council and public on September 6 in Seattle, Washington, September 22 in Boise, Idaho, October 5 in Helena, Montana, and October 20 in Portland, Oregon. The Council provided an opportunity for public comment at each of those meetings and public comments were incorporated into the studies. This issue paper describes the results of these staff studies.

This analysis addressed the following questons: Are the WPPSS plants cost-effective and needed based on the Council's forecast and resource plan adopted in April, 1983? What is the lowest-cost alternative for WNP 3 --

immediate restart of construction, continued ramp down to a mothballed condition late next year, or termination? Do the risks associated with delaying construction outweigh any cost advantages (if there are any)?

This staff issue paper does not represent the position of the Northwest Power Planning Council. The Council is seeking additional public comment on the staff's analysis and on the other issues that should be considered in a determination of the most desirable construction schedule for the WPPSS plants. The Council is scheduled to hear public comment and consider the staff's recommendations on November 2 in Seattle, Washington.[1] Any one who wishes to comment but is unable to attend the meeting should send written comments to the Council's Portland office by November 1. The address is room 200, 700 S.W. Taylor, Portland, Oregon 97205.

II. STAFF RECOMMENDATION

The Council and staff have engaged in extensive consultations with interested parties and based on these consultations and other public comment consderable analysis has been conducted. Based on this analysis the staff makes the following recommendations to the Council.

- WNP 1, 2, and 3 are cost-effective resources.
- WNP 2 is needed in all load forecasts and should be completed on its current schedule.
- WNP 1 and 3 are needed in three out of the four load forecasts. If these plants are lost and loads grow at the high, med-high, or med-low rates, additional thermal resources would be needed to replace their energy.
- Because WNP 3 is cost-effective and needed in three out of four load forecasts, the region needs to secure the ability to finance

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[1] The Mercer Forum, Rooms III and IV, Mercer Street and 3rd Avenue North, Seattle, Washington.

completion of the project. Based on consultations with interested parties, the staff has concluded that the Supply System does not have access to conventional financing. An alternative financing approach would require action by the Congress, the courts and the Bonneville Power Administration. A mechanism for financing to completion of the project is needed independent of the decision of when to restart construction.

- Immediate restart of WNP 3 is approximately the same cost as delayed restart where the plant is built precisely when needed in each load forecast. Other factors that cannot be evaluated quantitatively must be a part of the Council's decision on the importance of an early restart.

If the Council decides to take a position on restart or delay of WNP 3, many factors that are difficult to estimate must be included. These factors can only be included through a subjective evaluation by the Council.

The factors of greatest significance include the possibility that as a result of delay, the plant ends up being terminated. This may occur even though the plant is needed and other higher cost resources would be required. WNP 3, like all nuclear plants, does not make a particularly attractive "option" as envisioned in the plan. Any nuclear plant at 75% complete is going to have both high hold costs and significant risks of cost increases, schedule delays and the possibility of termination.

Another factor involves the inability of the region to restart plant 3 at this time because of the lack of financing. This is a question of BPA's borrowing authority since WPPSS is not likely to be able to go to financial markets until legal issues involving WNP 4 and 5 are resolved.

A third factor is the uncertainty in WPPSS costs estimates and construction schedules. Not only are the current estimates uncertain but a protracted delay is likely to result in greater cost and schedule uncertainty.

Another factor to be considered is the likely impacts of delay on the Investor Owned Utilities (IOU) who will continue to compound interest on their sunk investment of $725 million. Over a period of five years delay in plant completion, the sunk costs could increase by $600 million in interest alone.

Attempts have been made in the analysis to account for the value of the energy provided at the end of a plant's useful life. In cases where WNP 3 is available for a longer period of time into the future than in immediate restart, there could be a value for the additional energy output in the future of the delayed case. In estimating this value, the analysis is forced to speculate about the cost and need for resources in the years 2020 to 2025.

Several factors may tend toward delay by providing the WPPSS organization with an opportunity to reorganize contracts and improve construction efficiency. Some of these improvements have already occured, however, additional improvements may exist.

It is also possible that the current high interest rates may decline over time and that a decision to delay may be able to take advantage of lower interest rates.

Because of these and other uncertainties, the staff recommends at this time that the Council seek additional public comment at the November 2 and 3 Council meetings on these and other issues affecting the decision to resume construction.

III. ANALYSIS OF ALTERNATIVES FOR WNP 3

A. Decisions Being Evaluated

The decision analyzed in this issue paper is whether WNP 3 is cost effective to complete, and if it is cost effective, what is the best schedule on which to complete it. The Council's staff has analyzed a number of scenarios falling into three basic types; immediate restart, delayed restart and termination of the plant. The termination scenarios have included immediate termination, termination following delay and termination of only WNP 3 or both WNP 1 and 3. The decision regarding the best schedule was analyzed both on the costs directly related to immediate restart or delaying the plant's restart and on the possible effect of delay on any subsequent termination. Although the costs of immediate restart compared to delay are relatively quantifiable, the analysis of how delay might increase the risk of termination is more subjective.

The basic decision structure is illustrated in Figure 1. One branch shows a decision to immediately restart with the associated present value system costs from the System Analysis Model. These costs are for capital, production, and secondary power sales to California for all resources over their life times. The analysis includes only the production costs on existing resources since their capital costs are "sunk costs" to this analysis. The other branch shows a decision to delay restart, which could result in two other branches successful restart when WNP 1 and 3 are needed to meet regional loads or failure to restart due to some unforeseen circumstances.

Each of the four load forecasts have different probabilities. Figure 2 illustrates the likelihood (cumulative probability) that the actual load will be less than a particular compound growth rate. These distributions were developed in the Council's regional power plan and show that there is a 33 percent probability of loads being below the medium-low, 44 percent probability of being between the medium-low and the medium-high, and a 23 percent probability of being higher than the medium-high and below the high. These estimates of probability were used in choosing resources for the regional energy plan and are used here to estimate the expected cost of immediate restart, delayed restart, and termination.

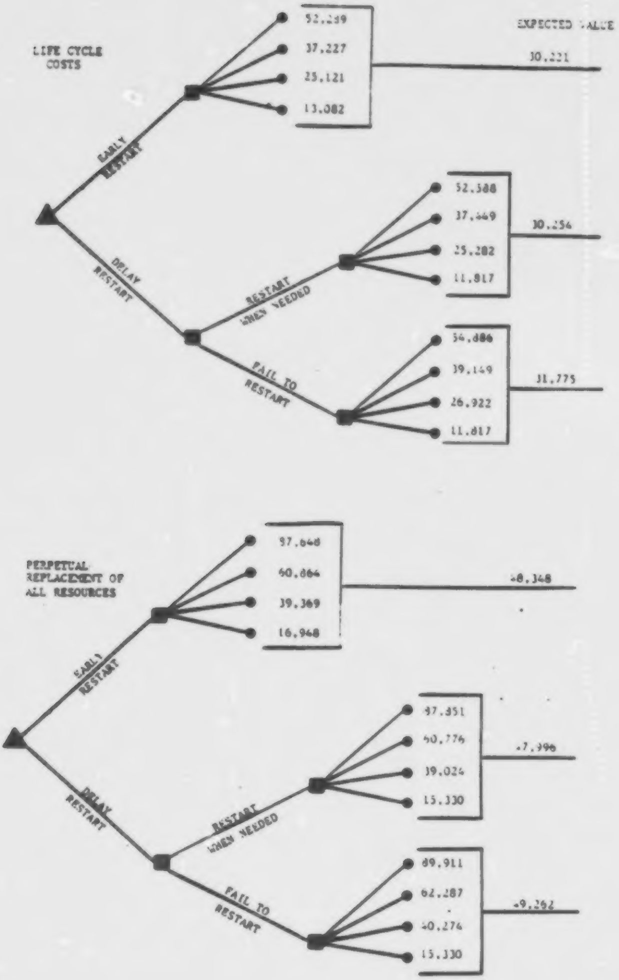
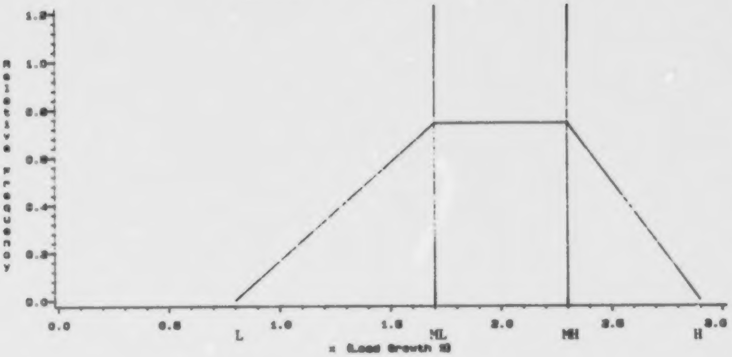

LIFE CYCLE COSTS
EXPECTED VALUE
EARLY RESTART
52,239
37,227
25,121
13,082
30,221
DELAY RESTART
RESTART WHEN NEEDED
52,388
37,449
25,282
11,817
30,254
FAIL TO RESTART
54,886
39,149
26,922
11,817
31,775
PERPETUAL REPLACEMENT OF ALL RESOURCES
EARLY RESTART
87,648
60,864
39,369
16,948
48,348
DELAY RESTART
RESTART WHEN NEEDED
87,351
60,776
39,024
15,330
47,996
FAIL TO RESTART
89,911
62,287
40,276
15,330
49,262

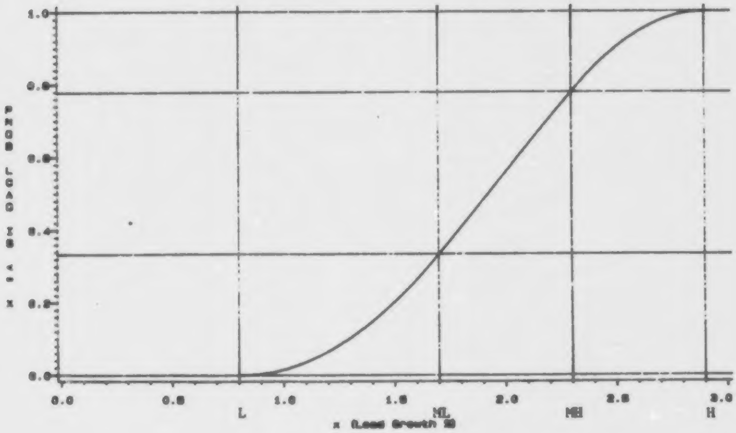
Figure 1. Decision Structure

Figure 2

PROBABILITY DISTRIBUTION FOR LOAD



CUMULATIVE PROBABILITY DISTRIBUTION FOR LOAD



B. Summary of WNP 3 Results

The Council staff studies of the cost-effectiveness of the Supply System plants have evaluated many alternative schedules for each plant and for the other resources included in the Council's Plan. The most important of these studies are summarized in Table 1 where seven basic scenarios were evaluated across each of the four load forecasts. In this table the first three scenarios are the scenarios of greatest importance to the Council's decision analysis. They include: first, an immediate restart of plant 3 with subsequent completion of plant 1 in the high, medium-high and medium-low load forecasts when it is needed. In the low load forecast, sufficient conservation resources exist to meet the projected load growth needs of the region over the next 20 years. However, plant 3 is assumed to be built in all load cases and in the low, WNP 3 is surplus for the entire period. WNP 1 is not built in the low.

The second scenario involved delaying restart of WNP 3, and, like the first scenario, the subsequent completion of WNP 1 in the high, medium-high and medium low load forecasts when it is needed. In this scenario, neither WNP 3 nor WNP 1 is needed in the low, and therefore neither plant is constructed to meet regional needs.

The third scenario involves a termination of both WNP 1 and 3. In this scenario, it is assumed that the region has embarked on a delayed restart of WNP 3 as suggested in the second scenario. However, at the end of a hold period, WNP 3 is terminated rather than restarted with the termination costs estimated by the Supply System. For comparison purposes the fourth scenario involves the termination of WNP 3 only with the subsequent completion of WNP 1 in the high, medium-high and medium-low load forecasts. The fifth scenario involved an immediate termination of both WNP 1 and 3 by initiating termination in January of 84. Likewise, scenario six involves an immediate termination decision but only of WNP 3. Subsequently, WNP 1 is assumed to be completed based on the needs of the high, medium-high and medium-low load forecasts. Again, neither plant is completed in the low. Finally, immediate restart was evaluated with a 4% interest premium on the financing costs of WNP 3 and the same resource schedules as in the first scenario were assumed.

The analysis illustrated in Table 1 shows the results of using the Systems Analysis Model (SAM) to evaluate the expected costs of constructing and operating the regional power system over the lifetimes of all resources included in this study. To this we must add hold and termination costs in those cases where one or more of the plants are not completed. Also, where differences in allowances for funds used during construction (AFUDC) on the sunk costs of the investor-owned utilities are relevant, we must add those to the costs estimated by the SAM studies. The present value impact on the region's ratepayers of differing lengths of hold on WNP 3 are shown in the column titled "AFUDC On Sunk." The combination of the first three columns -- costs estimated by the Systems Analysis Model, hold and termination costs, and AFUDC costs on the IOU sunk investment -- are combined to estimate the lifecycle costs in each of the load forecasts for each scenario (column entitled "Life Cycle").

As was discussed earlier, to correct for possible "end effects," additional studies were conducted where the resources involved in these studies were replaced in perpetuity with generic resources with specific costs. Caution should be exercised in interpreting the results of these perpetual replacement studies. First of all, the costs estimated here are for costs of resources that are going to be replacing resources in each study at the end of

Table I

WNP 3 COST EFFECTIVENESS ANALYSIS

(Millions of 1981 Dollars)

					Perpetual Replacements Costs				Expected Costs			
										Perpetual Replacements		
Study		System Analysis	Hold & Terminate Costs	AFUDC On Sunk	Life Cycle	Low Cost Conservation	Medium Cost Coal and Conservation	High Cost Coal	Life-Cycle Average Costs	Low	Medium	High
Immediate Restart	H	52,289	0	0	52,289	73,863	87,648	144,324	30,221	42,295	48,348	81,787
	MH	37,227	0	0	37,227	52,321	60,864	101,618				
	ML	25,121	0	0	25,121	35,228	39,369	68,310				
	L	12,727	355	0	13,082	16,686	16,988	28,689				
Delayed Restart	H	52,521	0	67	52,588	74,130	87,851	144,469	30,234	42,160	47,996	81,139
	MH	37,354	0	95	37,449	52,443	60,776	101,438				
	ML	25,129	0	153	25,282	35,158	39,024	67,491				
	L	11,230	561	26	11,817	15,175	15,330	26,637				
Terminate 3 and 1	H	54,840	133	-87	54,886	76,432	89,911	146,825	31,773	43,604	49,262	82,336
	MH	38,873	327	-31	39,169	54,116	62,287	103,031				
	ML	26,400	522	0	26,922	36,648	40,274	68,522				
	L	11,230	561	26	11,817	15,175	15,330	26,637				
Terminate 3 Only	H	53,504	23	-87	53,440	75,001	88,496	145,443	31,310	43,141	48,796	81,897
	MH	38,230	87	-31	38,266	53,236	61,410	102,161				
	ML	26,682	168	0	26,850	36,374	40,198	68,441				
	L	11,230	561	26	11,817	15,175	15,330	26,637				
Immediate Termination 1 and 3	H	54,840	104	-111	54,833	76,379	89,838	146,772	31,550	43,379	49,037	82,017
	MH	38,873	236	-111	38,998	53,963	62,136	102,880				
	ML	26,400	349	-111	26,638	36,364	39,990	68,238				
	L	11,230	349	-111	11,468	14,826	14,981	26,288				
Immediate Termination 3	H	53,504	-6	-111	53,387	74,968	88,443	145,390	31,084	42,915	48,570	81,671
	MH	38,320	-6	-111	38,203	53,173	61,347	102,098				
	ML	26,682	-6	-111	26,565	36,289	39,913	68,136				
	L	11,230	349	-111	11,468	14,826	14,981	26,288				
Immediate Restart .49	H	52,731	0	0	52,731	74,325	88,110	144,786	30,683	42,757	48,810	82,249
	MH	37,689	0	0	37,689	52,783	61,326	102,080				
	ML	25,583	0	0	25,583	35,690	39,831	68,772				
	L	13,189	355	0	13,544	17,148	17,410	29,151				

607

their lifetimes. These replacements will occur in the period between 2020 and 2030. Because of the very large uncertainties in the type and cost of resources that might exist 30 to 50 years into the future, these estimates must be viewed with some degree of suspicion. Nevertheless, when evaluating alternatives that involve slipping the schedule of a particular resource, the slipped resource will probably have a longer period of operation and value into the future than the same resource which was constructed on an earlier schedule.

Three cases were evaluated: 1) a low cost scenario where all resources were replaced with resources of comparable cost to the average of all conservation measures included in the plan; 2) a medium cost scenario involving conservation measures replacing conservation and generic coal plants used to replace all generating resources (the generic coal assumed in these studies is the estimated capital and fuel costs of the Council's generic coal plants in the year 2002); 3) a high cost scenario using generic coal plants of approximately twice the cost of our generic coal plants in the year 2002 to replace all resources used in the study. The resulting total present value system cost as estimated under these three perpetual replacement scenarios are illustrated in Table 1.

Finally, for each of the basic scenarios, the overall expected costs were calculated using the probability distribution on load that was shown previously in Figure 2. This probability distribution was used to weight the expected cost of each of the four load forecasts. These overall expected costs are shown for all plants involved in the study over their lifecycle and for the three perpetual replacement cases -- either low cost conservation, coal and conservation, or high cost coal used as the primary replacement resource.

Figures 3-7 display graphically the results for the scenarios of immediate restart, delay, termination of WNP 1 and 3, and termination of WNP 3 only. Figure 3 portrays life cycle system cost present values for each scenario under each load forecast. Figure 4 shows similar information but uses the medium perpetual replacement costs rather than life cycle. Figure 5 shows the differences between immediate restart and the other scenarios on a life cycle cost basis, and Figure 6 displays the same information using perpetual replacements. On these difference charts, a negative value (or a bar extending to the left of zero) indicates a lower cost for that scenario than for immediate restart in the same load condition, and a positive value represents a comparative cost increase. Finally, Figure 7 is another difference chart showing the relationships between the expected values of costs for each scenario across all load forecasts on both a life cycle and perpetual replacement cost basis.

By referring to Figure 7, one can see that the overall expected cost of immediate restart or delayed restart over the lifecycle of all plants is extremely close with only a $33 million present value advantage to immediate restart. The overall expected costs increase significantly if as a result of delay WNP 1 and 3 are terminated. This cost increases the expected lifecycle costs from $30,221 million to $31,775 million. This approximately $1.5 billion increase is due to the cost-effectiveness of WNP 1 and 3 in meeting regional loads and the necessary replacement of those resources with other higher cost thermal should they be terminated.

The slight advantage that immediate restart enjoys over plant lifecycles disappears when perpetual replacements are factored in. In all three perpetual replacement scenarios, delayed restart is favored over immediate

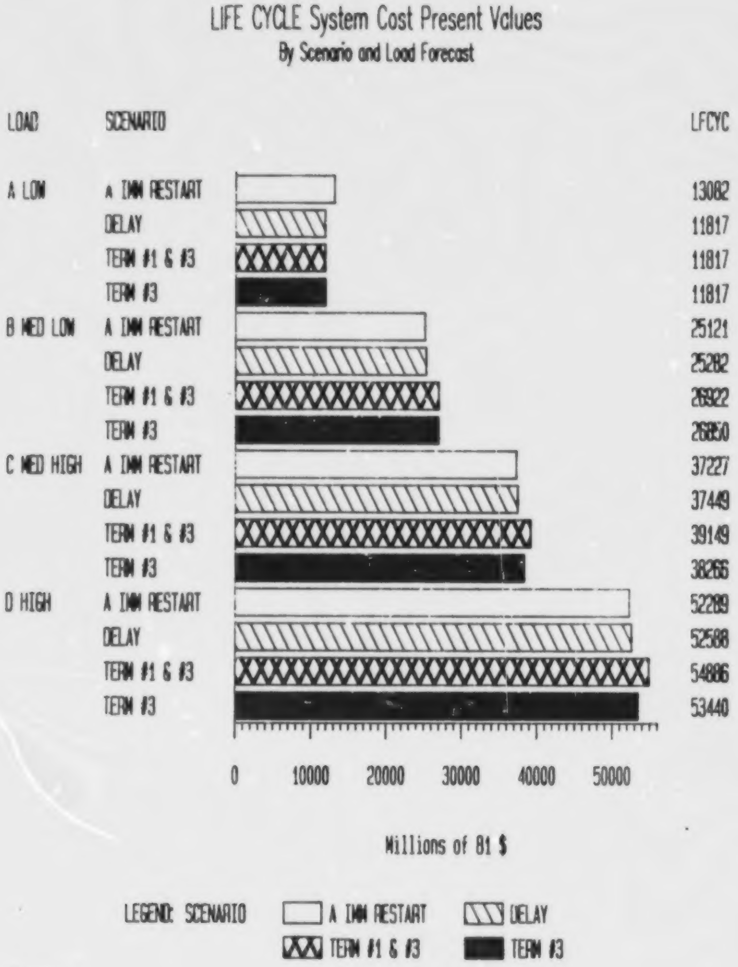

LIFE CYCLE System Cost Present Values
By Scenario and Load Forecast
LOAD
SCENARIO
LFCYC
A LOW
A IMM RESTART
13082
DELAY
11817
TERM #1 & #3
11817
TERM #3
11817
B MED LOW
A IMM RESTART
25121
DELAY
25282
TERM #1 & #3
26922
TERM #3
26850
C MED HIGH
A IMM RESTART
37227
DELAY
37449
TERM #1 & #3
39149
TERM #3
38266
D HIGH
A IMM RESTART
52289
DELAY
52588
TERM #1 & #3
54886
TERM #3
53440
0
10000
20000
30000
40000
50000
Millions of 81 $
LEGEND: SCENARIO
A IMM RESTART
DELAY
TERM #1 & #3
TERM #3

Figure 3

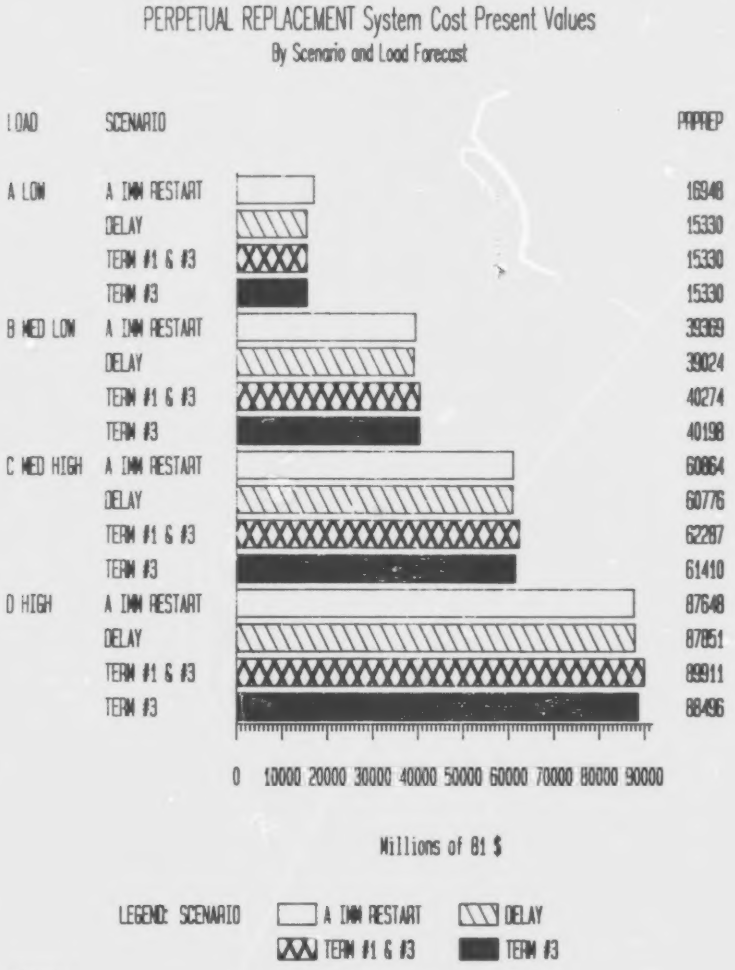

PERPETUAL REPLACEMENT System Cost Present Values
By Scenario and Load Forecast

Figure 4

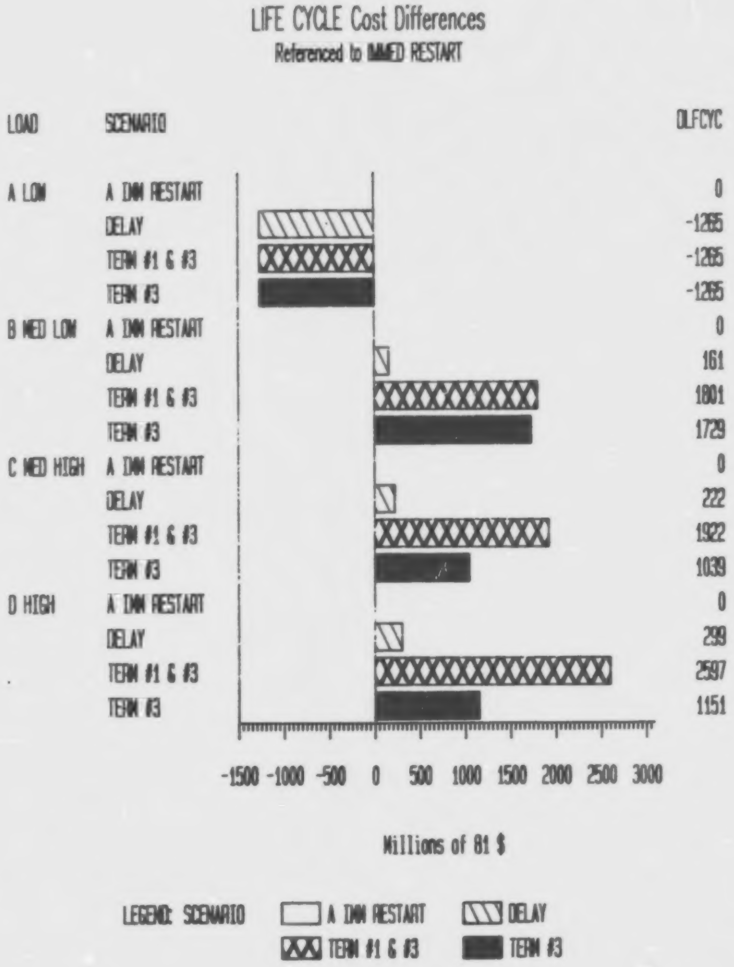

LIFE CYCLE Cost Differences
Referenced to IMMED RESTART
LOAD
SCENARIO
DLFCYC
A LOW
A IMM RESTART
0
DELAY
-1265
TERM #1 & #3
-1265
TERM #3
-1265
B MED LOW
A IMM RESTART
0
DELAY
161
TERM #1 & #3
1801
TERM #3
1729
C MED HIGH
A IMM RESTART
0
DELAY
222
TERM #1 & #3
1922
TERM #3
1039
D HIGH
A IMM RESTART
0
DELAY
299
TERM #1 & #3
2597
TERM #3
1151
-1500
-1000
-500
0
500
1000
1500
2000
2500
3000
Millions of 81 $
LEGEND: SCENARIO
A IMM RESTART
DELAY
TERM #1 & #3
TERM #3

Figure 5

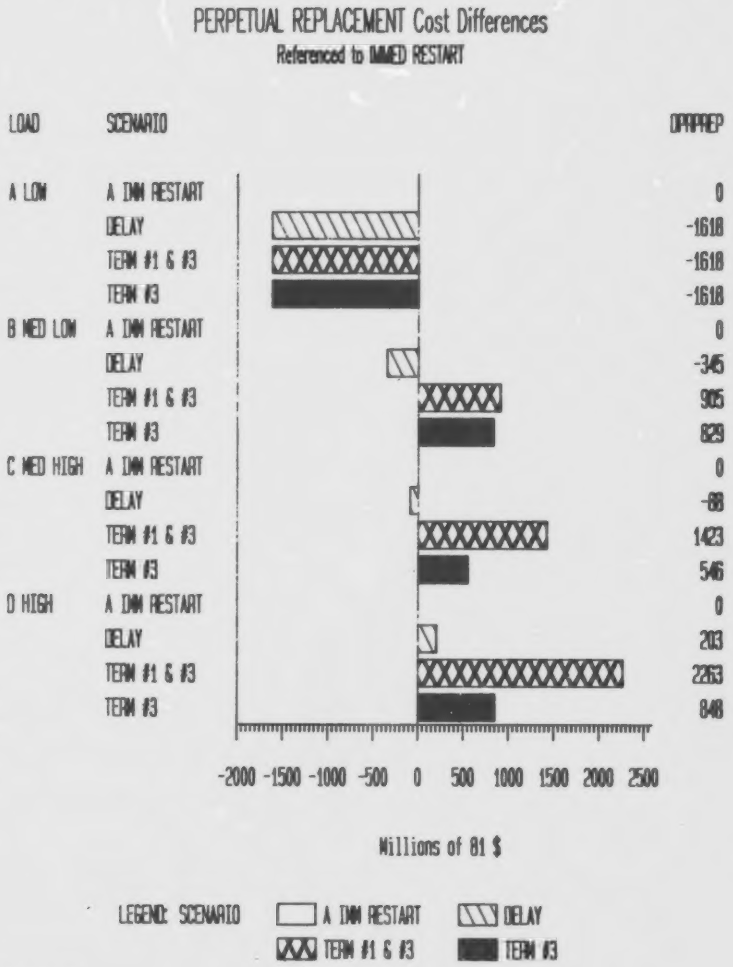
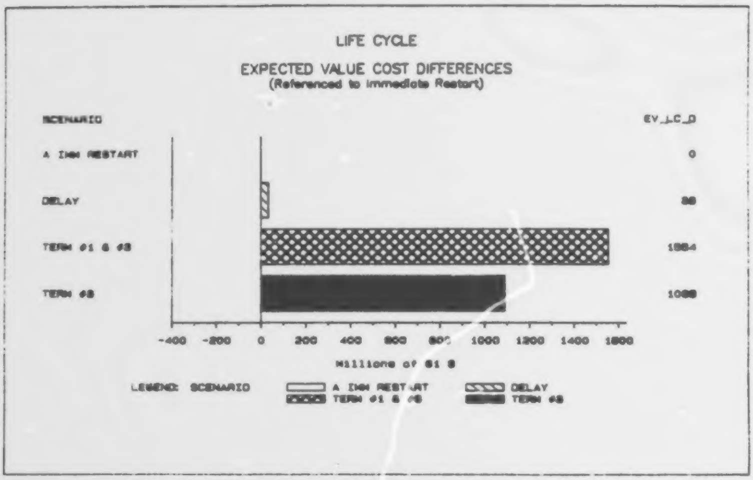

PERPETUAL REPLACEMENT Cost Differences
Referenced to IMMED RESTART
LOAD
SCENARIO
DPRPREP
A LOW
A IMM RESTART
DELAY
TERM #1 & #3
TERM #3
B MED LOW
C MED HIGH
D HIGH
0
-1618
-1618
-1618
0
-345
905
829
0
-88
1423
546
0
203
2263
848
-2000
-1500
-1000
-500
0
500
1000
1500
2000
2500
Millions of 81 $
LEGEND: SCENARIO
A IMM RESTART
DELAY
TERM #1 & #3
TERM #3

Figure 6


LIFE CYCLE
EXPECTED VALUE COST DIFFERENCES
(Referenced to Immediate Restart)
SCENARIO
EV_LC_D
A IMM RESTART
0
DELAY
36
TERM #1 & #3
1554
TERM #3
1088
-400
-200
0
200
400
600
800
1000
1200
1400
1600
Millions of 81 $
LEGEND: SCENARIO
A IMM RESTART
DELAY
TERM #1 & #3
TERM #3

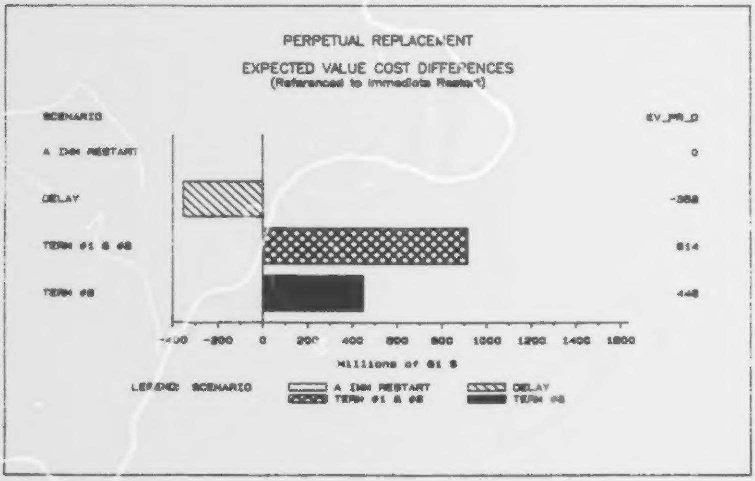

PERPETUAL REPLACEMENT
EXPECTED VALUE COST DIFFERENCES
(Referenced to Immediate Restart)
SCENARIO
EV_PR_D
A IMM RESTART
0
DELAY
-358
TERM #1 & #3
914
TERM #3
448
-400
-200
0
200
400
600
800
1000
1200
1400
1600
Millions of 81 $
LEGEND: SCENARIO
A IMM RESTART
DELAY
TERM #1 & #3
TERM #3

Figure 7

restart; however, as before all termination cases involve significantly higher costs.

From these studies the cost-effectiveness of plants 1 and 3 is clear and both resources will be needed if loads in the region grow at the medium-low load forecast or above. Since these resources are needed in three out of four of the Council's forecasts, it appears particularly prudent at this time to continue to hold WNP 1 and 3 in anticipation of their ultimate need as regional generating resources.

The analysis is not particularly helpful in deciding whether an immediate restart of WNP 3 is either prudent or necessary. For this reason, a decision to restart WNP 3 will probably be made on grounds other than the expected total system costs.

C. Input Assumptions

Input assumptions for the analysis were developed building on those assumptions employed in the cost comparison of WNP 4 and 5 versus new coal plants reported in Appendix G of the Northwest Conservation and Electric Power Plan, Volume II, April 27, 1983. That cost comparison benefitted from extensive public involvement regarding the appropriate input assumptions to be used. Because the WNP 4 and 5 analysis did not focus on WNP #3 and because circumstances surrounding the Supply System have changed over the past ten months, the Council held a new round of consultations. Public comment was also elicited at Council meetings on August 17, 18, September 6, 7, September 21, 22, October 5, 6, and October 19, 20.

PACIFIC POWER & LIGHT COMPANY
920 S.W. SIXTH AVENUE · PORTLAND, OREGON 97204 · (503) 243-1122

David F. Bolender
President

October 26, 1983

Honorable Jim Weaver, Chairman
Subcommittee on Mining, Forest
Management, and Bonneville Power
Administration
Committee on Interior and Insular Affairs
U.S. House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

Enclosed per your request are Pacific Power & Light Company's responses to the questions you posed to Northwest investor-owned utilities.

I hope they are helpful to you and the members of the Subcommittee.

Thank you for your interest in our views.

Sincerely,

David F. Bolender

QUESTIONS FOR NORTHWEST INVESTOR-OWNED UTILITIES

1. BPA's final studies for the 1983 rate proposal show an expected operating year (OY) 1985 residential exchange cost of $1156 million and residential exchange revenues of $809 million, for a net transfer to the exchanging utilities of $347 million. Is $1156 million a reasonable projection of BPA revenue from power sales to exchanging utilities?

Pacific's Response to Question 1

The numbers given are reasonable. However, they also can be misleading. Bonneville does not actually make a $1156 million payment to exchanging utilities, and Bonneville will not collect $809 million. The actual cost of the exchange is the amount paid as a net transfer, which amount is used to equalize the wholesale power costs of public and private residential and small farm customers. The large numbers are ratemaking adjustments only. Accordingly, BPA substantially has overstated its actual revenue requirement and its actual rate increase.

2. What control over BPA's budgets and expenditures is available to BPA's customers?

Pacific's Response to Question 2

The customers of BPA are able to make limited challenges to BPA's planned expenditures during rate proceedings. However, the Office of Management & Budget restricts BPA from sharing budget information with its customers until presentation to Congress. This restriction can impede open discussion of planned expenditures during the ratemaking process.

3. What suggestions do the Northwest Investor-Owned Utilities have for improving BPA's repayment performance?

Pacific's Response to Question 3

Bonneville's difficulties have arisen in large part because its sales have fallen far short of its forecast sales. This result probably has occurred as a result both of the price effects of the Bonneville rate increases and the effects of the recession. Northwest utilities have proposed improvements to the Bonneville forecasts, which in substantial measure have been adopted by Bonneville in the prior rate proceeding. This adoption, coupledwith an

Pacific's Response to Question 3 (Con't)

improving economy, hopefully will eliminate Bonneville's failure to make its repayments.

4. With BPA implementation of Regional Act Section 7 (b) (2) rate test for publicly owned utilities and the 7 (c) (1) (B) rate methodology for the Direct Service Industries, how long will the residential exchange remain viable for the Investor-Owned Utilities after June 30, 1985?

Pacific's Response to Question 4

Rate parity for domestic and rural customers is a fundamental element of the Regional Power Act. If Section 7 (b) (2) is construed in the manner Pacific will urge, this rate parity should be preserved.

5. What is the position of the Northwest Investor-Owned Utilities on HR3177, the proposed BPA Fair Rate Making Act of 1983?

Pacific's Response to Question 5

The provisions of HR 3177 are quite reasonable. In particular, requiring preparation by a hearings officer of written findings of fact based on the hearings record could be a constructive addition to the decision-making process at BPA. The separation of the initial trier of fact from the BPA staff, prohibition of exparte contacts and extension of the right to cross-examine on new issues raised by the Staff are important procedural benefits.

6. Would the Northwest Investor-Owned Utilities favor a proposal requiring BPA to submit rate adjustments to FERC for confirmation and approval six months prior to the proposed effective date, if FERC were (1) required to complete its review (both under Regional Act Section 7 (a) (2) and Section 7(k), based on the record in BPA's proceeding within the six month period, and (2) empowered to order all BPA rates increased by uniform percentage to cover any perceived prospective revenue shortfalls?

Pacific's Response to Question 6

FERC probably could not complete an adequate review of BPA's rates, and give an adequate opportunity for participation by other parties, within a six month period. Further FERC has disclaimed responsibility for review of all rate allocation and design issues other than those related to rates for sale of nonfirm energy outside the region. A uniform percentage adder could produce serious rate inequities and could damage BPA's ability to market its nonfirm power.

7. What are the conclusions of the Northwest investor-owned utilities' most recent analyses of the cost-effectiveness of resuming construction of WPPSS 3? Please provide the important assumptions and methodology used to derive these conclusions.

8. How soon could construction resume at WPPSS 3? If any of the key managers of the project have been lost, how long would it take to replace them? How much of the workforce (managerial and manual) has been laid off or terminated? How many of these people have left the Satsop area for work elsewhere?

Pacific's Response to Questions 7 and 8

Pacific and the other private owners of WPPSS 3 have challenged the extended construction delay implemented by the Supply System and Bonneville. This matter is in litigation and documents filed in the pending case, Bonneville Power Administration, et al v. Washington Public Power Supply System, et al, No. C82-1252, United States District, Western District of Washington, set forth Pacific's position. Pacific believes that the actions of the Supply System and Bonneville in suspending construction of WPPSS 3 have substantially increased the risk of non-completion and have materially impaired the cost-effectiveness of the project.

9. If WPPSS 3 were not completed, could the Northwest investor-owned utilities recover their investments in the plant under Washington law? Under Oregon law?

Pacific's Response to Question 9

Requests for recovery of terminated nuclear plant costs have been allowed under Washington law. Recovery has not been approved in Oregon, but the matter is presently before the Oregon Public Utility Commission.

10. Do the Northwest investor-owned utilities intend to sign BPA's long-term conservation contracts as presently offered? Which elements of these contracts require improvement?

Pacific's Response to Question 10

Pacific would like to enter into a long-term conservation contract with the Bonneville Power Administration. It cannot justify signing the presently proposed contract, however, because contract terms make conservation activities under the BPA program more expensive for the company's customers than they would be under company programs.

The additional expense to Pacific's customers under the BPA contract would result from a contract charge which, among other things, attempts (1) to recover BPA's 1982-83 conservation expenses primarily from those utilities which, with their customers, have been most active in pursuing conservation in the past, and (2) to focus increased conservation activity in those areas where utilities have been less aggressive in pursuing conservation to date.

As a result of these factors and BPA's current allocation of conservation benefits in the next two years, Pacific's customers would pay several million dollars more for conservation under the long-term contract than they would receive in benefits. Because of the allocation of benefits is unspecified after two years, there is no assurance these short-term losses will be recovered in the long-term.

Pacific continues to meet with BPA representatives on these matters, and is hopeful that the problems described above can be resolved in the near future.

11. Do the Northwest investor-owned utilities favor a "mitigation by exclusion" approach to maintenance of indoor air quality in residential weatherization programs?

Pacific's Response to Question 11

Pacific is aware of the uncertainties surrounding the indoor air quality questions arising as a result of weatherization activity. We do not recommend that conservation measures be excluded, but that indoor air quality concerns be addressed as they are identified. Mitigation action should be the result of an IAQ evaluation. Sufficient data should be maintained to allow the retrofitting of affected dwellings at such time as any long-term hazard is identified.

Portland General Electric Company
121 S.W. SALMON STREET
PORTLAND, OREGON 97204

JAMES W. DURHAM
[illegible]
[illegible]

October 25, 1983

The Honorable James Weaver
U.S. House of Representatives
1226 Longworth House Building
Washington, D.C. 20515

RE: October 27-28, 1983 Hearings of the Subcommittee on Mining, Forest Management, and the Bonneville Power Administration

Dear Congressman Weaver,

Attached are Portland General Electric Company's answers to the "Questions for Investor-Owned Utilities".

We are parties to the BPA rate case now pending before the Federal Energy Regulatory Commission. We are also actively involved in litigation with Bonneville Power Administration concerning WNP-3. It would be inappropriate for us to appear before a legislative body on these matters while they are before FERC and the Court.

Sincerely,

RESPONSE OF PORTLAND GENERAL ELECTRIC COMPANY
TO
QUESTIONS FOR NORTHWEST INVESTOR-OWNED UTILITIES

1. BPA's final studies for the 1983 rate proposal show an expected Operating Year (OY) 1985 residential exchange cost of $1156 million and residential exchange revenues of $809 million, for a net transfer to the exchanging utilities of $347 million. Is $1156 million a reasonable projection of BPA revenue from power sales to exchanging utilities?

PGE Response

Bonneville Power's estimate of the cost of the exchange is slightly underestimated. The Intercompany Pool has recently offered testimony on average system cost projections. Our testimony indicated that average system cost for operating year 1985 will be on the order of $1,200 million. The difference between Bonneville's estimate and the estimate provided by the region's investor-owned utilities was due to a difference in forecasting methodology. The region's exchanging utilities actually attempted to estimate future operations and costs on a utility-by-utility basis. Bonneville simply trended current costs into the future. The major components of the difference were in the areas of wholesale power sales, transmission plant additions, new generation plants in rate base, and federal taxes.

An exchange adjustment clause has been included in the final record of decision. The exchange adjustment clause will correct for any forecasting errors made by the Bonneville Revenue Requirements staff. At this time, we would expect that the exchange adjustment clause will reflect the average system cost forecast made by the Intercompany Pool when these costs are faced by Bonneville.

The projection of BPA revenues from power sales to exchanging utilities is reasonable. The $809 million estimate is simply the product of rates times loads. At this time, Portland General Electric Company has no reason to believe that any major discrepancies in Bonneville's short-run forecast of exchanging loads have occurred.

2. What control over BPA's budget and expenditures is available to BPA's customers?

PGE Response

Bonneville's customers have some degree of review over Bonneville's budget and expenditures. The budget process at Bonneville actually includes two different areas of review.

The first, based on the financial year, is provided through the Office of Management and Budget, followed by Congressional review. The second, taking place later in the year, is the analysis of revenue requirements that occurs in Bonneville's rate case, mandated by § 7(i) of the Regional Power Act.

The requirements of OMB that restrict Bonneville from sharing budget information with its customers until presentation to Congress currently tend to collide with rate case review of revenue requirements. The inconsistency between the OMB/Congressional review and Bonneville's annual rate case appears to reduce the ability of either analysis to give the fullest possible review to Bonneville's budget and expenditures.

3. What suggestions do the Northwest investor-owned utilities have for improving BPA's repayment performance?

PGE Response

Bonneville's repayment performance has been poor over the last five years. The investor-owned utilities, with the support of the DSIs and public agencies in the Pacific Northwest, have made a number of recommendations to alleviate these problems. First, Bonneville's load forecast should be as precise and accurate as possible. Second, Bonneville should adopt adjustment procedures that enable it to maintain its revenue stream when load or revenue requirement changes occur. These adjustment procedures should operate with adequate notice and timing to allow BPA customers to adjust their rates to cover the revised cost. Third, Bonneville should seriously consider a reform of its repayment methodology in order to bring it closer to standard utility depreciation practice.

The most recent Bonneville rate case (the 1983 BPA Rate Case) responded to many of the proposals of Bonneville's customers. Bonneville load forecasts have improved significantly, and adjustment clauses have been included in significant areas. Bonneville should now direct its attention to the repayment methodology (i.e., conversion to standard industry practice).

4. With BPA implementation of the Regional Act § 7(b)(2) rate test for the publicly-owned utilities and the § 7(c)(1)(B) rate methodology for the direct service industries, how long will the residential exchange remain viable for the Northwest investor-owned utilities after June 30, 1985?

PGE Response

The two issues raised in this question are separable. The first, the rate test, is difficult to forecast at this time. The rate test language in the Act is complex. PGE believes BPA must perform a careful analysis of what rates in the Pacific Northwest would have been in the absence of the Northwest Regional Bill. Assuming that PGE's interpretation of § 7(b)(2) is accepted and the Administrator makes no radical rate decisions, the implementation of this part of the bill will not change the operation of the domestic and rural power exchange.

Section 7(c)(1)(B) of the Act prescribes the design of electric rates for direct service industrial customers after 1985. By stipulation in the 1981 BPA rate case and inclusion in the general contract provisions, § 7(c)(1)(B) will be implemented in accordance with Exhibit U in the 1981 BPA rate case. Exhibit U was prepared by all regional parties to represent the rate design described by the legislative history and included in the rate provisions of the Act. Exhibit U leaves open a critical question. The degree of the markup over the regional rate that the DSIs will bear post-1985 is not yet established . Alternatives for this markup range from 10 to 50 percent. If the DSI rate is low by comparison with the regional rate, Bonneville's financial health could easily be impaired. This is because, after 1985, the rate to the DSIs is no longer cost-based. If their rate is set low compared to the underlying revenue requirements, Bonneville will have difficulty recovering its costs.

Substantial concern has been caused by the use of a rate forecasting model at Bonneville called the Supply Pricing Model. The results from this model are inconsistent with other information and models on the post-1985 period, and should be disregarded.

5. What is the position of the Northwest investor-owned utilities on H. R. 3177, the proposed BPA Fair Ratemaking Act of 1983?

PGE Response

H. R. 3177 recommends an increase in the responsibility for the hearings officer entrusted with the § 7(i) rate proceedings. This increase in responsibility has been endorsed by the investor-owned utilities as a method of helping Bonneville staff cope with the difficult challenge of acting as both rate proponent and judge. It is the belief of the investor-owned utilities that an independent hearings officer would encourage the parties to focus on specific policy differences and reduce the massive litigation of the past few years.

The procedural direction and technical mastery of the hearings officers presiding over the first three BPA § 7(i) proceedings have been excellent. H. R. 3177 would enable these competent trial experts to shoulder more of the burden that is currently borne by the Administrator. At the same time, it does not eliminate the Administrator's freedom to exercise the serious responsibilities of his office. H. R. 3177 enables the Administrator to overrule the hearings officer, but to do so after a "full and complete" explanation.

6. Would the Northwest investor-owned utilities favor a proposal requiring BPA to submit rate adjustments to FERC for confirmation and approval 6 months prior to the proposed effective date, if FERC were (1) required to complete its review (both under Regional Act § 7(a)(2) and § 7(k), based on the record in BPA's proceeding, within the 6-month period, and (2) empowered to order all BPA rates increased by a uniform percentage to cover any perceived prospective revenue shortfalls?

PGE Response

The investor-owned utilities do not support a required six-month review at FERC. The § 7(i) proceeding is complex and lengthy. An attempt to provide a full half-year review at FERC might yield a situation where the region's customers were being forced to operate in an environment where Bonneville's rate proceedings could take longer than a full year. Since Bonneville is required to make rates on a yearly basis, this could involve its customers in overlapping and confusing proceedings. A thorough FERC review is important to the Bonneville rate process. Mandating a lengthy review, however, would not ensure that such a review was thorough and met all the conditions of the Regional Act. The existence of an independent hearings officer, as in H. R. 3177, will go far in meeting many of the concerns that are addressed by a six-month mandatory FERC review.

7. What are the conclusions of the Northwest investor-owned utilities' most recent analyses of the cost-effectiveness of resuming construction of WPPSS 3? Please provide the important assumptions and methodology used to derive these conclusions.

8. How soon could construction resume at WPPSS 3? If any of the key managers of the project have been lost, how long

would it take to replace them? How much of the workforce (managerial and manual) has been laid off or terminated? How many of these people have left the Satsop area for work elsewhere?

9. If WPPSS 3 were not completed, could the Northwest investor-owned utilities recover their investments in the plant under Washington law? Under Oregon law?

PGE Response to Questions 7, 8, and 9

PGE seeks the early completion of WPPSS 3. The issues rasied by questions 7, 8 and 9 are currently being litigated in Bonneville Power Administration, et al v. Washington Public Power Supply System, et al, No. C82-1252 (Bilby), United States District Court, Western District of Washington. Detailed comments outside this litigation are not appropriate.

10. Do the Northwest investor-owned utilities intend to sign BPA's long-term conservation contracts as presently offered? Which elements of these contracts require improvement?

PGE Response

PGE is unlikely to sign BPA's long-term conservation contracts as presently offered. The most serious problem is that of a proposed contract charge, which remains at such a high level for generating utilities such as ourselves that, as a group, our customers would see as much as a $15 million penalty in signing the contract.

11. Do the Northwest investor-owned utilities favor a "mitigation by exclusion" approach to maintenance of indoor air quality in residential weatherization programs?

PGE Response

PGE acknowledges the considerable uncertainty about measurement and causation of indoor air quality problems when buildings are tightened. However, we don't believe that conservation programs should be stopped based on current knowledge. Our preference is for mitigation action taken only after investigation of the presence and magnitude of an IAQ problem. Basically, we prefer to look and see before action is taken.

PUGET
POWER

October 25, 1983

The Honorable James Weaver
Subcommittee on Mining, Forest Management,
and the Bonneville Power Administration of the
Committee on Interior and Insular Affairs
U.S. House of Representatives
Washington, D.C 20515

Dear Congressman Weaver:

Puget Sound Power & Light Company, has received your letter of October 12, 1983 inviting representatives of the Northwest investor-owned utilities to participate in hearings on October 27-28, 1983 before your Subcommittee.

As you know, Puget Power is actively involved in litigation in federal district court concerning WPPSS Unit No. 3 which is one of the subjects which you invite us to discuss at the hearing. In addition, Puget Power participated in BPA's most recent rate proceeding and has continued such participation in the BPA rate proceedings now before the FERC. Many of the issues which you invite us to discuss at the hearing are also issues in these ongoing proceedings. In view of the fact that these same issues are presently being litigated in court and administrative proceedings, it would not be proper for us to appear on these issues before your Subcommittee.

Although we cannot appear before your Subcommittee on October 27-28, we have endeavoured to submit some written answers to the "Questions for Northwest Investor-Owned Utilities" appended to your October 12, 1983 letter. These answers are submitted solely on behalf of Puget Power and we understand that the other Northwest investor-owned utilities will be submitting their own answers to the extent they deem it appropriate to do so. Our written answers are quite short and necessarily incomplete given the ongoing court and administrative proceedings which directly or indirectly deal with the same issues.

Thank you for affording us the opportunity to appear before your Subcommittee and we hope that the enclosed answers are of some assistance to the Subcommiittee.

Very truly yours,

John W. Ellis, President and
Chief Executive Officer

Puget Sound Power & Light Company Puget Power Building Bellevue, Washington 98009 (206) 454-636

Response of Puget Sound Power & Light Company

to

Questions for Northwest Investor-Owned Utilities

1. Bonneville Projections of Exchange Costs and Revenues. The question refers to $1156 million as an estimate of the cost of the exchange and similarly refers to $809 million as a projection of BPA exchange revenue. However, we are not aware of the source of those estimates, and they do not appear to exactly coincide with certain numbers in the Bonneville final studies. These voluminous studies have been prepared by Bonneville after the close of its rate hearings and have not been subjected to questioning and verification in a hearing process.

2. BPA Budget and Expenditures. The Bonneville rate hearings under the Regional Power Act have to date served as a source of information about Bonneville's proposed expenditures and have provided some opportunity to question the reasonableness of BPA's future course of action (or at least to present evidence with respect to a future course of action). In general, it does not appear that any additional formal budget review procedures are necessary, assuming such issues are aired in the Bonneville rate process.

3. BPA Repayment. One approach for both reducing BPA's future repayment obligations and facilitating the rate at which present Bonneville obligations are repaid to the federal treasury is to reduce future federal investment in transmission lines. In many cases, the region's utilities are willing to participate, on an ownership basis, in the construction of transmission facilities, including lines on federal right-of-way. Bonneville should be encouraged to pursue this approach whenever possible.

   In establishing its rates, Bonneville should make reasonable estimates of quantities and prices of surplus sales. Such estimates are an important element of a realistic rate case and should reflect not only a reasonable judgment with respect to market conditions but should also be based on compliance with Bonneville's existing contractual and other legal obligations.

4. Viability of Investor-Owned Utility Residential Exchange After June 30, 1985. Providing the domestic and rural customers of investor-owned utilities with access to low-cost federal power, both before and after June 30, 1985, has

always been a fundamental element of the Regional Power Act. The exchange was intended to be viable after June 30, 1985, and the provisions of the act must be construed consistent with this intention.

5. H.R. 3177. See the attached excerpt from the June 30, 1983 statement of Puget before Representative Ottinger's subcommittee with respect to H.R. 3177.

6. Fixed 6-month FERC Review Period and Uniform Adder for Perceived Prospective Revenue Shortfalls. The Federal Energy Regulatory Commission has misconstrued the scope of its authority to review Bonneville rates and has incorrectly concluded that it does not have responsibility for the many important rate design issues raised by Bonneville's rate filings. Accordingly, FERC review under its present interpretation is of limited value. In this context, a uniform percentage adder, as suggested by the questions, is particularly inappropriate since it will merely compound any unfair or incorrect Bonneville rate design decisions. A more fundamental difficulty is that Bonneville rates must reflect a fair and accurate allocation of costs between power and transmission services and also a fair and accurate allocation of costs between federal and non-federal uses of the federal transmission system. A percentage adder is clearly not consistent with this requirement. Finally, there are a considerable number of practical difficulties with the percentage adder, including the allocation of percentage increases between capacity and energy rates. Obviously, a percentage adder could not be allocated only to energy or only to capacity but would have to be allocated somehow to both.

7-9. Mothballing of WPPSS 3. The Bonneville study of mothballing Project 3 inadequately addressed the costs of the 30% of Project 3 owned by the investor-owned utilities. These costs should not have been ignored. The attached Memorandum in Support of Motion for Preliminary Injunction expresses positions taken by us with respect to mothballing of Project 3.

10. Long-Term Conservation Contract. Presently, it does not appear to be in our customer's best interests for Puget Power to sign BPA's long-term conservation contract as offered.

11. Residential Weatherization. We unfortunately cannot answer this question without a clear definition of what is meant by "mitigation by exclusion." Furthermore, the question assumes there is an indoor air quality problem which has not been established.

EXCERPT

HR 3177 is a technical amendment to the Regional Power Act which is consistent with the original purposes of the Act and with other legislation governing Bonneville ratemaking. It does not solve all the problems which parties to the Bonneville ratemaking process have raised. However, it is a good amendment which should be widely supported by Bonneville's customers. The bill emphasizes fairness in the ratemaking process by requiring the hearing officer to be an independent decision maker. This will help relieve the problems inherent in Bonneville staff serving as advocate, judge and jury. The bill also aims to solve the problem of additional studies and revised rates becoming a part of the record without adequate opportunity for cross-examination. This legislation can provide some better assurance of procedural fairness to parties in the rate process.

San Diego Gas & Electric

R. W. WATKINS
VICE PRESIDENT - RESOURCE MANAGEMENT

November 1, 1983

FILE NO

Honorable James Weaver, Chairman
Subcommittee on Mining, Forest Management
and Bonneville Power Administration
Committee on Interior and Insular Affairs
United States House of Representatives
1626 Longworth Building
Washington, DC 20515

Dear Congressman Weaver:

San Diego Gas & Electric Company (SDG&E) welcomes the opportunity to respond to the Subcommittee's questions regarding Bonneville Power Administration's (BPA) ratemaking practices and procedures. SDG&E looks forward to maintaining the long relationship between BPA and other Northwest utilities and SDG&E which has benefited the ratepayers of all parties.

Attached are SDG&E's responses.

Sincerely,

R.W. Watkins

R.W. Watkins

RESPONSES TO

QUESTIONS FOR CALIFORNIA UTILITIES AND AGENCIES

1. Surplus firm power sales

SDG&E did not purchase firm power from BPA in FY 1983 nor does it expect to in OY 1985.

2. Nonfirm surplus energy sales

SDG&E has made no projections of nonfirm purchases from BPA.

3. BPA Sales to California

SDG&E has not made projections of BPA purchases. However to the extent that BPA adheres to its proposed policy of selling to California primarily at the standard rate instead of the spill rate, SDG&E would expect relatively fewer purchases from BPA because of competing economy energy markets.

4. Customers control over BPA's Budget and Expenditures

SDG&E appears to have little control. In the recent 1983 BPA rate case SDG&E encouraged BPA to price its nonfirm energy and its transmission service based on generally accepted cost of service principles. Instead BPA has chosen to set prices to California at a premium above cost of service. These premiums are to subsidize other BPA customers. In the short term, this may work but in the long run it may backfire in pricing BPA resources above others available to SDG&E.

5. Improving BPA's Repayment Performance

BPA should establish its rates based on cost of service principles thereby eliminating subsidies between classes of its customers. If each customer pays its cost of service there should be no repayment problem. As discussed in Question 4, the premium added to BPA rates to California will probably be only of short term benefit to BPA's current repayment problems.

6. HR 3177: BPA Fair Ratemaking Act of 1983

HR 3177's proposal to have the authority of the administrative law judges (ALJ) expanded from being a referee to being responsible for rate approval is a good concept. This would remove to an extent the ratemaking approval from BPA thereby adding a greater degree of impartiality. To strengthen this impartiality, selection of an ALJ should be done by someone other than BPA; possibly the Federal Energy Regulatory Commission (FERC).

Even with this restriction, HR 3177 still allows the BPA Administrator to set aside the ALJ's decision and establish rates with no additional hearings other than by FERC. This provision basically voids the concept of an impartial ALJ ruling on BPA rates. Therefore HR 3177 only partially addresses SDG&E's concerns with BPA ruling on its own rates.

7. BPA submittal to FERC six months before rates become effective

In concept SDG&E supports the proposal to have a reasonable time limit on FERC's review and approval of rates before their effective date. By doing so, an expeditious hearing would be assured. However, the Regional Act Sections 7(a)(2) and 7(k) provisions are in the middle of being tested in BPA's 1981-82 Rate Case before FERC. SDG&E would prefer to obtain the benefit of this test of existing provisions before establishing new legislation.

The proposal to allow FERC to raise rates by a uniform percentage for all BPA rates to cover perceived revenue shortfalls provides the mechanism for subsidies between classes of BPA customers. It might further set precedents for increasing rates that would be difficult to undo. SDG&E would prefer that FERC apply increases to those customer classes not paying their proper cost of service as opposed to an increase to all rates.

8. BPA Non firm sales to SDG&E

August 1983	83,107 Mwhrs
September 1983	4,302 Mwhrs

9. Intertie Expansion Plans

The only significant change in plans since the July 11, 1983 Subcommittee hearings is in the status of the Intertie upgrade from 2800 MW to 3200 MW. This has been delayed because of technical problems. Resolution to this problem is under review.

SDG&E does not agree that if no agreements for substantial intertie expansion have been reached within one year that BPA and WAPA should seek congressional approval to develop the most cost-effective intertie additions. Unless BPA or other Northwest utilities can reach agreement with California utilities as to the long term availability of energy priced on consistent cost of service principles, an additional intertie is not justified.

10. BPA Intertie Access Policies

Attached is SDG&E's response of September 15, 1983 to BPA's requests for comments on this policy.

SDGE
San Diego Gas & Electric

September 15, 1983 FILE NO 83-037.08.01

Ms. Donne L. Geiger
Public Involvement Manager
Bonneville Power Administration
Post Office Box 12999
Portland, OR 97212

Subject: BAP Intertie Access Policy

File No: TIE-1

Dear Ms. Geiger:

This is in response to your request of July 15, 1983, for recommendations regarding the development of a BPA policy on providing access to the Pacific Northwest-Pacific Southwest Intertie. San Diego Gas & Electric Company (SDG&E) appreciates this opportunity to offer comments to assist in formulation of BPA's policy.

Introduction

All Northwest utilities should have the opportunity to have firm two-way transmission service as well as one-way firm and non-firm transmission service. Charges for such should be based on cost of service and transmission loss reimbursements should be based on actual line losses. The "lost opportunity" cost discussed by BPA is inappropriate as it is not based on the cost of providing transmission service.

A policy based on the above will maximize benefits to the Northwest and the Southwest. This will also be consistent with national objectives of maximizing the use of renewable resources, minimizing oil and gas consumption, and conserving energy.

1. How can BPA best determine the amount of intertie capacity, if any, which is excess to the Government's needs?

From BPA's share of the firm rating of the Intertie subtract the capacity associated with both BPA's firm contractual agreements with the Southwest and BPA's firm transmission agreements with others. The remainder is excess to BPA's needs.

2. How can BPA best provide access to Northwest Intertie capacity which is excess to the Government's needs?

Access to this excess should be open to all Northwest utilities. The history of the Intertie is replete with examples of this from Congressional reports to BPA's own statements. BPA should not now attempt to monopolize the Intertie. Any attempt to do so could have long range implications for potential upgrades or additional facilities.

3. What consideration should BPA require to grant transmission right to Intertie capacity otherwise needed by the Government? How should the rights of other entities, such as parties to the Exportable Agreement, be considered?

Any consideration for transmission granted by BPA should be limited to recovering the cost of service of the facilities and to be made whole for transmission losses. Other consideration such as "lost opportunity" cost is inappropriate as aforementioned. The Federal Energy Regulatory Commission has opposed value based rates of which "lost opportunity" charges is merely a variation.

BPA should also allow the firm transmission currently provided to utilities, such as Washington Water Power (WWP), to be extended beyond their termination. The WWP transmission has been used for long term capacity and energy transactions with SDG&E to the benefit of each party's ratepayers. Other Northwest utilities should be afforded similar opportunities for transmission providing mutual benefit to the Northwest and Southwest.

4. What priorities should be established by BPA in providing Intertie access for deliveries from the Pacific Northwest to the Pacific Southwest?

Firm transmission service should have the highest priority since this is consistent with national objectives of maximizing the use of renewable resources, minimizing oil and gas consumption, and conserving energy. Utilities currently having firm transmission agreements with BPA should have a priority in extending these agreements. If firm transmission is oversubscribed then the longest terms requested should have priority. As opposed to short terms, these long terms generally enable planning to be done to maximize benefits to both regions. A lower priority should be given to nonfirm transmission because of the associated uncertainty.

5. What terms of service should BPA offer for transmission on the Intertie?

All rates for service should be established to recover the cost of service of the facilities. BPA should be able to adjust its rates and losses whenever it can demonstrate a change has occurred but not more than once per year. Loss reimbursement should recover actual line losses. Firm two-way and one-way service should be offerred with a term of at least five years. The latter is needed to provide the certainty needed for optimal planning of resources. Non-firm service should be offerred as well for economy energy transactions.

SDG&E has welcomed this opportunity to comment and looks forward to further participation as the Intertie access policy evolves.

Respectfully submitted

M G Strong

M.G. Strong
Senior Power Contracts Administrator

Southern California Edison Company

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2244 WALNUT GROVE AVENUE

ROSEMEAD, CALIFORNIA 91770

SCE

GLENN J. BJORKLUND
VICE PRESIDENT

TELEPHONE
213-572-4173

October 24, 1983

Honorable James Weaver, Chairman
Subcommittee on Mining, Forest Management
and Bonneville Power Administration
Committee on Interior and Insular Affairs
United States House of Representatives
1626 Longworth Building
Washington, DC 20515

Dear Congressman Weaver:

Regarding the Subcommittee's hearing on major Northwest power issues to be held on October 27 and 28, 1983, the Southern California Edison Company will not testify at this proceeding but is pleased to submit its comments on BPA ratemaking practices and procedures. Edison is an active participant in BPA rate proceedings on behalf of its ratepayers and is interested in the Subcommittee's hearing concerning this matter.

Edison values its relationship with BPA and the Pacific Northwest which has benefitted ratepayers in both regions. Edison believes that these benefits can continue to accrue to the ratepayers of the Pacific Northwest and California through combined efforts based on mutual interests.

Thank you for providing Edison the opportunity to participate in these hearings.

Sincerely,

Glenn Bjorklund

POST OFFICE BOX 1831 • SAN DIEGO CALIFORNIA 92112 • TELEPHONE 619/232-4252

COMMENTS AND RESPONSE OF SOUTHERN CALIFORNIA EDISON COMPANY REGARDING BPA RATEMAKING PRACTICES AND PROCEDURES

I.

INTRODUCTION

The Southern California Edison Company ("Edison") welcomes the opportunity to comment on the issues raised by the Subcommittee regarding the Bonneville Power Administration's ("BPA") ratemaking practices and procedures. These comments are directed toward maintaining the relationship that has existed between the Pacific Northwest and Pacific Southwest which has benefited the ratepayers of both regions.

Cooperation for the mutual interests and benefit of both the Pacific Northwest and Pacific Southwest has existed since the formulation of the agreements leading to the construction of the Pacific Northwest/Pacific Southwest Intertie ("Intertie"). The Intertie has enabled entities in both regions to take advantage of seasonal peak load diversity between the regions, to exchange surplus capacity and energy, and to enter into nonfirm energy transactions.

In 1982 Edison purchased approximately 11 billion kWh of nonfirm energy from the Pacific Northwest. Of that total, Edison purchased 5.4 billion kWh from BPA alone. As of September 1983, Edison has purchased approximately 6.5 billion kWh from the Pacific Northwest of which approximately 6 billion kWh were purchased from BPA. Additionally, Edison receives 550 MW of firm peaking capacity from BPA in exchange for firm energy. These capacity and energy transactions have benefited and will continue to benefit both Edison and the Pacific Northwest.

BPA is unique in several respects. By statute, BPA has a responsibility to serve the needs of the Pacific Northwest before providing energy for sale outside the region. In addition, with the passage of the Pacific Northwest Electric Power Planning and Conservation Act ("Regional Act"), BPA now has the responsibility to meet the firm load growth of publicly-owned entities and investor-owned utilities in the Pacific Northwest that request BPA to undertake such obligation.

In practice, BPA has designed its rates so as to depend on recovering revenues in excess of its costs from nonregional nonfirm energy customers in order to reduce increases in the rates paid by its regional firm energy customers that would otherwise be required. In so doing, BPA has miscalculated the revenue it expected to receive by overestimating its regional and nonregional loads, thus increasing its repayment problems while providing a rate preference to its regional customers. BPA's obligation to meet the electric energy needs of the Pacific Northwest does not mean that the Northwest is entitled to a preference in the rates for energy generated by the Federal Government. The applicable statutes do not provide for such a rate preference. Taxpayers in all regions of the country contributed to financing the construction of Federal generating facilities in the Pacific Northwest. There is no basis for giving any one region a preference with respect to the amount charged for energy generated at Federal facilities. Section 7(k) of the Regional Act was included in the Act to prevent such regional discrimination in BPA's rates.

The Congressional intent behind the inclusion of Section 7(k) in the Regional Act is to (1) protect BPA's nonregional nonfirm energy customers from discriminatory rate treatment and (2) establish that rates for nonfirm energy sold to BPA's nonregional customers should be based on the cost of providing nonfirm energy. As explained below, Section 7(k) of the Regional A[illegible] so far has not prevented BPA from designing and administering its rates for energy sales to the Pacific Southwest in a manner which is discriminatory and this provides an undue preference to BPA's customers in the Pacific Northwest. Edison believes that, as a result of BPA's apparent disregard for the protection afforded nonregional customers by Section 7(k) of the Regional Act, further Congressional action may be required to implement the intent behind Section 7(k). In addition, FERC has not provided a timely review of BPA's 1979, 1981, and 1982 nonfirm energy rate schedules. Not only has BPA's treatment of its nonregional customers been discriminatory, BPA's ability to stabilize its revenues and pay off its obligations to the Federal Treasury has been jeopardized by its ratemaking practices.

II.

EDISON'S OBJECTIVES IN THE BPA RATE PROCEEDINGS

As noted above, Edison purchases substantial amounts of nonfirm energy from BPA. Such nonfirm energy is only offered to nonregional customers if there is no market for the energy in the Northwest. In addition, such energy may be interrupted by BPA without notice if BPA requires the energy to serve its firm or nonfirm loads in the Northwest. On the other hand BPA, pursuant to statutory requirements, gives priority to service to its regional customers and therefore designs and operates its system to serve the firm load requirements of the Pacific Northwest. BPA does not design or operate its system to meet the needs of its nonregional nonfirm customers. The nonfirm energy marketed by BPA to its nonregional customers is, therefore, an inherently inferior product than the firm service BPA provides its regional customers and should be priced accordingly. BPA has failed to consider this ratemaking principle in designing its nonfirm energy rates. For example, in the 1983 BPA rate proceeding the proposed NF-83 standard rate is higher than the energy component in the priority firm power rate charged to BPA's Northwest customers even though BPA's nonfirm energy service provides no capacity value to the purchaser.

Since 1979 BPA has adopted a variety of inconsistent and improper rate designs, particularly in setting its nonfirm energy rates. BPA's nonfirm energy rates have been excessive and the changes in the rates have been unpredictable. It is Edison's position that not only are cost of service ratemaking principles required by the statutes governing BPA's rates, but that they constitute sound ratemaking principles which will better serve the interests of both regions and better enable BPA to meet its revenue requirement and repayment obligations to the Federal Treasury. This position has been advocated by Edison in its participation in the 1979, 1981, 1982, and 1983 BPA rate proceedings.

Edison has pursued two related objectives in its participation in BPA rate proceedings. As a public utility, Edison has a fundamental obligation to all of its ratepayers to provide electric service at the lowest possible cost. Access to low cost energy from the Pacific Northwest, produced primarily by Federal hydro-electric generating facilities has, in the past, assisted Edison in providing electricity to its ratepayers at lower costs than if the energy had been generated by Edison's thermal generating facilities or purchased from others. The related objective of Edison is to increase the mutual benefits derived by both regions from surplus capacity and energy transactions by increasing the transmission capacity linking the two regions. This is a difficult objective to achieve when BPA's rates are excessive and unpredictable.

Edison currently supplies a significant amount of the energy required to meet its load through power purchased from other entities such as BPA, other Pacific Northwest entities, and entities in California and the Pacific Southwest. Approximately 80 percent of Edison's purchased power are nonfirm energy purchases. These nonfirm energy purchases assist Edison toward meeting its public utility obligation to minimize its costs. Since 1979 the cost of nonfirm energy sold by BPA has risen in relation to other suppliers of honfirm energy to the point where BPA is increasingly pricing itself out of the market. Edison's participation in the BPA rate proceedings has been directed at urging BPA to price its nonfirm energy based on properly allocable costs. Doing so would avoid the incongruous result that BPA nonfirm energy, produced largely from low cost Federal hydro resources, is priced higher than the incremental costs of many of the thermal generating resources in the Pacific Northwest and Pacific Southwest. In recent months, Edison has displaced nonfirm energy purchases it otherwise would have made from BPA with less expensive nonfirm energy purchases from entities in California and the Southwest. If the upward trend in BPA's nonfirm energy rates continues, Edison's displacement of BPA purchases will only further increase which will decrease BPA's revenues.

Expanding the Intertie could be a benefit to both the Pacific Northwest and Pacific Southwest. Edison's ratepayers could benefit by increased access to relatively low cost energy while BPA's customers would benefit by BPA's ability to market more of its unsold regional surplus. Investment in additional Intertie facilities is not likely to occur as long as BPA's rates remain unpredictable and excessive in relation to the costs to provide nonfirm energy. Without Intertie expansion, the ultimate mutual benefits obtainable from full utilization of surplus renewable hydro resources in the Northwest cannot be achieved.

Establishment of BPA's rates should be directed toward the efficient use of renewable hydro resources for the benefit of all of BPA's customers and their ratepayers. To the extent BPA's rates encourage the burning of fossil fuels to generate electricity in either the Northwest or Southwest while water is spilling over the dams, efficient use of this country's resources is not achieved. As will be explained below, characteristics cf

BPA's proposed 1983 nonfirm energy rates now before FERC for interim approval, provide an undue rate preference for BPA's Northwest customers at the expense of California ratepayers and could lead to BPA revenue instability and the inefficient use of this country's resources.

III.

EDISON'S POSITION IN THE BPA RATE PROCEEDINGS

Edison's position in the BPA rate proceedings has been and continues to be that the statutes governing BPA ratemaking mandate that BPA use cost of service ratemaking principles in designing its rates. Such principles are accepted by FERC and most state public utility commissions in determining the level of electric rates to be charged by investor-owned utilities. Cost of service ratemaking principles more fairly distribute the costs of providing electric service among customer classes and enhance the likelihood of the selling entity recovering its revenue requirement. BPA should be held to no less a standard.

BPA has deviated from those principles particularly in setting its nonfirm energy rates in the 1979, 1981, 1982 and 1983 rate proceedings. In the 1979 rate proceeding, BPA based its nonfirm energy rates on a share-the-savings formula which resulted in a rate that exceeded its costs of providing such energy. The nonfirm energy rates in the 1981 BPA rate proceeding were based on a variable formula which in essence permitted BPA to charge whatever the market would bear. Finally, in the 1982 and 1983 rate proceedings, BPA based its nonfirm energy rate on an average of its total system costs. BPA did not purport to have conducted a cost of service analysis to properly assign allocable costs to the nonfirm energy rate. BPA's nonfirm energy rates, under which nonregional customers purchase a substantial portion of the energy they buy from BPA, have exceeded the energy charge in the firm power rates paid by BPA's regional customers. This has been the case even though nonfirm energy sales to nonregional customers have the lowest priority for BPA and the costs incurred to provide such service are substantially less than the costs incurred by BPA to serve its firm customers in the Northwest.

This regional rate preference at the expense of BPA's nonregional customers will most likely be increased as a result of BPA's proposed implementation of the 1983 nonfirm energy rates. BPA has proposed to base the availability of the various components of the NF-83 nonfirm energy rate schedule on its own nonreviewable determination of whether its revenues will be increased by switching from one nonfirm energy rate to another. Such a mechanism for implementing the nonfirm energy rates appeared for the first time in the Administrator's Record of Decision, released on September 30, 1983, as a practice advocated by BPA to administer its nonfirm rates. As a result, none of the parties in the proceeding had an opportunity, as required by Section 7(i) of the Regional Act, to examine BPA staff on the operational aspects of how such a practice would be implemented or to evaluate the merits of BPA's proposal. BPA's proposed mechanism for determining which rate is appropriate and will be applied at any particular time has no relationship to cost of service ratemaking principles. The NF-83 nonfirm energy rate schedule allows BPA to offer a lower rate for nonfirm energy to its Northwest customers while at the same time selling nonfirm energy at a higher rate to its Southwest customers. This results in unfair and, Edison believes, unlawful discrimination against nonregional nonfirm energy customers.

IV

EDISON'S RESPONSE TO QUESTIONS FOR THE CALIFORNIA UTILITIES AND AGENCIES

A. Edison's Purchased Power Practices

Consistent with its policy to provide least-cost energy to its customers, Edison actively pursues the purchase of power from other interconnected utilities in the western states, Canada, and Mexico. Edison attempts to obtain maximum benefits from power purchases through a combination of firm contracts, exchange agreements, and nonfirm energy transactions. In order to accomplish that goal, Edison attempts to achieve full utilization of its interties with other entities to the maximum extent possible. There are, however, several reasons why Edison is unable to keep its intertie capacity, including that of the Pacific Intertie, fully loaded. These involve the availability of purchases, the price of energy, transmission constraints, minimum-load restrictions, and system regulation and reliability considerations.

As a general practice, Edison's decisions to purchase available nonfirm energy are based on price rather than source within the constraints of available transmission capacity. However, there are times when Edison is unable to import all the power available. During such times, Edison must make the most economic purchases and decline to purchase more expensive power. Increasingly, this economic decision will lead Edison to reduce purchases from BPA in favor of other suppliers, as BPA's rates to California continue to increase out of proportion to BPA's cost of providing nonfirm energy and surplus firm power.

It should be remembered that Edison's alternative to purchasing power from BPA, or others in the Pacific Northwest, is not necessarily to produce electrical energy by consuming oil and gas on its electrical system, but, rather, to purchase power from others.

The Subcommittee's written questions indicate that BPA expects to increase its revenues from California sales while recognizing that the volume of such sales will decrease. BPA estimates that, in OY 1985, revenues from sales of nonfirm energy and surplus firm power sales, presumably to California, will total $387 million. Edison is not in a position to confirm these estimates, but believes such estimates are unrealistic if FERC approves BPA's proposed rates. This assessment is based upon Edison's belief that BPA's proposed nonfirm energy rates will be less attractive to Edison and other California utilities than alternative sources of energy available. No doubt Edison will purchase some nonfirm energy from BPA during OY 1985, and we are continuing discussions on potential surplus firm power sales. There are now too many variables and unknowns for Edison to provide a detailed response to the Subcommittee regarding BPA's forecast of total sales to California.

In August 1983, Edison purchased approximately 450,000 MWh of nonfirm surplus energy from BPA, dropping to less than 25,000 MWh in September and in October. Edison has no record that BPA offered to sell Edison nonfirm energy at the NF-2 Standard Rate during this period, although Edison would have been willing to purchase energy at that rate if it had been offered and was competitive with alternative nonfirm energy purchases.

Over the years, Edison's customers have benefitted from its purchases of nonfirm energy from BPA. Likewise, BPA's Northwest customers have gained from these transactions in the form of lower rates because such transactions reduced BPA's revenue requirements to be met by Northwest customers. Edison believes both regions have significant mutual interests in continuing these and other transactions, such as summer/winter diversity exchanges.

Edison is concerned about BPA's revenue stability as are BPA and the Subcommittee . When rates deviate from cost-of-service principles and too much reliance is placed on revenues from relatively unstable nonfirm energy sales, Edison believes revenue instability will result and the likelihood of BPA failing to meet its revenue requirement and repayment obligations will be increased.

B. Proposed Congressional Legislation Regarding BPA Ratemaking Procedure and FERC Review of BPA Rates

H.R. 3177, the proposed BPA Fair Ratemaking Act of 1983, addresses some of the procedural deficiencies in the current BPA ratemaking procedures as provided for in the Regional Act. In past BPA rate proceedings and in the recent 1983 BPA rate proceeding, BPA has filed testimony or exhibits late in the proceedings (and in the 1981 and 1983 BPA rate cases even after the close of hearings) which substantially changed the proposed rates. These late changes have made BPA rate cases "moving targets". Participants in these BPA rate proceedings have been unfairly deprived of an opportunity to fully present their cases.

Section 2(1) of the bill establishes procedures that would require additional opportunity be given to respond to any change in BPA's proposed rates. In Edison's view, Section 7(i)(4) of the Regional Act already adequately address the problems covered by Section 2(1) of the proposed bill. BPA's interpretation of this section of the Regional Act, however, has not been consistent with Edison's view, thus additional congressional action may be necessary. Section 2(2) of the bill expands the role of the hearing officer in the BPA ratemaking process. The bill, however, has a number of deficiencies which should be corrected.

Section 2(1)(D) of the bill is defective in not requiring BPA to give notice of a change in the proposed rates prior to any hearings on the revised rate proposal. This defect in the bill can be remedied by inserting an amendment to Section 7(i)(1) of the Regional Act and to Section 2(1)(D) of the bill as suggested below:

> "(i) Notice of the proposed rates and any revisions thereto shall be published in the Federal Register with a statement of the justification and reasons supporting such rates. Such notice shall include a date for a hearing in accordance with paragraph (2) of this subsection."

> "(D)if the Administrator requests, before the close of the record of the hearing, the hearing officer shall allow the Administrator to file revised rates, provided that the Administrator shall provide notice of such revised rates in conformity with the requirements of paragraph (1) of this subsection and that the hearing officer shall then allow adequate opportunity for cross-examination of such revised rates and any material submitted to support such rates and, for good cause shown, to offer rebuttal of such revised rates or supporting material."

In addition, the bill does not specify how the hearing officer should be selected. At present, the hearing officer is chosen by BPA. It is vital that the hearing officer's judgment be unbiased.

A substantial part of the problem associated with the BPA ratemaking process is the fact that there is no division of responsibility or of interests between the proponent of the rates and the decisionmaker. The BPA Administrator is at once the head of the staff submitting the rate proposal and, at the same time, the person responsible for making the ultimate decision on the proposed rates. FERC, except with respect to the nonregional, nonfirm energy rates, merely reviews the record created at BPA in order to decide whether to confirm and approve or remand the rates adopted by the Administrator. Section 7(k) of the Regional Act provides for an additional hearing at FERC only for nonregional, nonfirm energy rates. The actual scope of the 7(k) hearing has not been determined by FERC, since the first 7(k) hearing under the Regional Act is just getting underway.

FERC is the logical forum to handle BPA's proposed changes in its rates. Under such a procedure, BPA should be the proponent of a rate change before FERC similar to a utility seeking to change its rates for wholesale power. The decision-making process would be governed by well-settled FERC procedures that would give every participant a fair opportunity to present their cases. In addition, there would be some equity between the manner in which BPA would be treated and the way in which all other utilities subject to FERC jurisdiction are treated.

The Subcommittee's inquiry as to whether the California utilities favor a proposal requiring BPA to submit rate adjustments to FERC six months prior to the proposed effective date of the rates and to require FERC to complete its review under both Section 7(a)(2) and 7(k) of the Regional Act within the six month period deserves consideration. FERC has been slow in fulfilling its responsibilities under the Regional Act to review BPA's rates. However, compressing the total allotted time for FERC review, particularly the hearing required by Section 7(k), may deny BPA's regional and nonregional customers an opportunity to have BPA's proposed rates adequately examined by a regulatory body. For that reason, Edison would be reluctant to support such a proposal. A definitive response, however, cannot be given until a draft of the proposed bill is available.

C. Expansion of the Pacific Intertie

As Edison indicated at the Subcommittee's July 11, 1983, hearing in Eugene, Oregon, since the completion of the Intertie, the California utilities have increased the operating rating of the AC portion of the Intertie through improved operating procedures and special reliability-protection measures, including generator-unit tripping, transfer trip, and automatic customer load shedding. These enhancements have allowed the operation of the AC Intertie to increase to its current nonfirm operating limit of 2,800 MW. Efforts are underway to solve technical and operating problems associated with operating the AC lines above 2,800 MW.

The DC line also has been uprated from 1,400 MW to 1,560 MW, and construction is currently underway to uprate those facilities to 1,960 MW by 1985.

Edison firmly believes that upgrades and/or conversions of the existing Intertie facilities should be for the account of the Intertie owners who invested in those facilities in the early 1960s when extra-high voltage transmission was a new and emerging technology. In accordance with existing contractual arrangements, these owners are entitled to the benefits from that venture, which, in turn, accrue primarily to the ratepayers of those forward-looking utilities.

Edison suggests that participation in any new transmission lines between the two regions should be offered to any interested entity. It must be recognized, however, that there are obstacles to building a new transmission line between the Northwest and California. These obstacles lie primarily in the areas of licensing, right-of-way acquisition, Northwest capacity and energy price stability and availability, financing, and potential reliability impacts on the existing interconnected electric systems.

The time required to obtain regulatory authorizations, such as a Certificate of Public Convenience and Necessity from the California Public Utilities Commission, and the necessary rights-of-way, is considerable and could consume as much as 60% of the time necessary to put a new line in service. Reasonably reliable estimates of the availability and price of Northwest firm power and surplus energy are also important matters that need to be resolved in order to ensure that the investment in such transmission will be justified.

D. Edison's Position on BPA's Intertie Access Policy

The Department of the Interior report to Congress recommending construction of the Intertie is replete with statements which demonstrate that both the government and the nonfederal entities in the Northwest contemplated that open access for nonfederal entities in the Northwest to the Intertie would be provided on BPA's portion of the Intertie facilities. BPA assured both public and private utilities in the Pacific Northwest that they would be allowed access, proportionate to their respective surplus, to markets in the Pacific Southwest.

The historical development and contractual arrangements established regarding the Intertie mandate that BPA allow access to all entities in the Pacific Northwest with surplus power to sell. Therefore, BPA should not restrict other entities in the Pacific Northwest from access to the Intertie or attempt to control transactions that take place over the Intertie. These objectives can be achieved by BPA providing transmission service at prices based on cost and on a non-discriminatory basis to Northwest entities, whether Federal or nonfederal, as they enter into power purchase sales or exchange agreements with Southwest entities.

For a more thorough discussion of this issue, please see the attached Comments of Southern California Edison Company on BPA Intertie Access Policy submitted to BPA as part of BPA's public involvement process concerning this issue.

V.

CONCLUSION

Edison appreciates the invitation of the Subcommittee on Mining, Forest Management, and the Bonneville Power Administration to participate in its October 27, 1983, hearing on BPA revenue and repayment and on BPA ratemaking procedures. Edison has actively participated in all BPA rate proceedings and welcomes the opportunity to respond to the Subcommittee's written questions.

There are many complex issues which need to be considered such as BPA's rates, expanding the Intertie, and the efficient use of the country's natural resources. As an electric utility responsible for providing economic service to more than nine million people, Edison must be assured that the rates paid for purchased power and, hence, the rates charged our customers, are based on sound and equitable ratemaking principles. The cornerstone of these principles is that rates be based on the cost of providing the service being purchased. Any deviation from this principle invites inequities, confusion, and potentially unreliable revenues. Edison believes that BPA's recent revenue deficiencies are in a large part a result of deviating from this principle.

Southern California Edison Company

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MANAGER OF POWER CONTRACTS

TELEPHONE
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September 16, 1983

Ms. Donna L. Geiger
Public Involvement Manager
Bonneville Power Administration
P. O. Box 12999
Portland, Oregon 97212

Dear Ms. Geiger:

Subject: BPA Intertie Access Policy

In response to BPA's July 15, 1983 Notice of Intent to Develop Policy on Providing Access to the Pacific Northwest-Pacific Southwest Intertie, enclosed are Southern California Edison's (Edison) comments and recommendations. The comments are directed at the five Intertie access policy issues identified by BPA in the July 15 notice.

In summary, Edison believes that BPA should provide all entities, both federal and nonfederal, access to the Intertie, and in so doing, BPA should not dictate or interfere with transactions that take place on the Intertie except as required for maintenance and safety. Both of these objectives were mandated by the original Congressional authorization of the Intertie, and are consistent with the policies of the Federal Energy Regulatory Commission. These objectives can best be achieved by BPA providing transmission service at prices based on cost on a nondiscriminatory basis to Northwest entities, whether federal or nonfederal, as they enter into power purchase, sale, or exchange agreements with Southwest entities.

On July 15, 1983, when the notice was published, the Intertie AC lines were being loaded as high as 2800 MW at Malin. However, since then operating concerns over system reliability at times have reduced that loading limit to 2500 MW. Until those problems are resolved, it is uncertain that this limit will be raised on a regular basis, and the upgrade to 3200 MW referenced as background information in the July 15 notice is even more unlikely. This unfortunate reduction in Intertie capability amplifies the importance and timeliness of BPA developing an Intertie access policy.

Edison appreciates the opportunity to submit recommendations in development of BPA's Intertie access policy, and is ready to actively participate in the policy's evolution.

Sincerely,

LDHamlin

Enclosure

UNITED STATES OF AMERICA

BEFORE THE BONNEVILLE POWER ADMINISTRATION

In the Matter of the)
Bonneville Power Administration)
Intertie Access Policy.) File No. TIE-1

Comments of Southern California Edison Company on the BPA Intertie Access Policy

The comments of Southern California Edison Company on the BPA Intertie Access Policy are submitted in response to BPA's July 15, 1983 request for recommendations concerning BPA's Notice of Intent to Develop Policy on Providing Access to the Pacific Northwest-Pacific Southwest Intertie ("Intertie").

I.

INTRODUCTION

By letter dated August 30, 1982 (copy attached), Southern California Edison Company ("Edison") responded to a similar notice concerning BPA's transmission policy. At that time Edison noted three issues that deserve to be emphasized once again. First, BPA's objectives for transmission services should include furthering national objectives of minimizing the consumption of fossil fuels, conserving energy, and maximizing the use of renewable resources.[1] Maximizing transactions between utilities in the Pacific Northwest and those in the Pacific Southwest will promote these objectives. Second, BPA should provide Northwest utilities firm two-way transmission service to enable firm capacity and energy exchange arrangements with Southwest utilities, in addition to nonfirm, interruptible transmission service which only enables economy energy transactions. Third, BPA's charges for such services should be cost-based and should be allocated in an equitable manner to avoid one service subsidizing another service.[2]

In the current 1983 BPA rate hearings, Edison has been concerned by BPA's proposals to increase charges for wheeling non-BPA energy on the Intertie to subsidize other classes of service. Federal and nonfederal transactions on the Intertie should pay the same rates for the same service, and all such charges should collect only the cost of providing the service. [3] The federal government, through FERC, has a policy of supporting cost-based rates and opposing value-based rates.[4] For these reasons, BPA's recently proposed "lost opportunity" charge of 6 mills/kWh for firm service on the

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[1] Section 2 of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. §839) establishes those goals for BPA. See also the Public Utilities Regulatory Policies Act (16 U.S.C. §2601 et. seq.); and §202 (a) of the Federal Power Act (16 U.S.C. §824a (a)).

[2] 16 U.S.C. §839e (a) and 16 U.S.C. §§838g and 838h.

[3] See Exhibit Nos. WP-83-E-CE-02, at pp. 9-11, WP-83-E-CE-02S3, and WP-83-E-CE-02S4 filed in the 1983 BPA rate case (BPA file nos. WP-83 and TR-83).

[4] Please see, *U.S. Department of Energy, Bonneville Power Administration*, 23 FERC ¶61,342 at 61,740 (1983) and *U.S. Department of Energy, Bonneville Power Administration*, 23 FERC ¶61,378 at 61,798 (1983).

Intertie has been viewed by Edison with great alarm. Such rate-making policy directly results in a restrictive Intertie access policy designed to extract revenue for sales which BPA has not made. At the last possible opportunity, BPA staff withdrew the "lost opportunity" charge from consideration in the 1983 BPA rate case, but left the possibility open that such a proposal or other restrictive Intertie access policies may be adopted later as a result of this Intertie access policy development process.[5/] BPA should not use its monopoly position over Intertie transmission to unfairly restrict Intertie access and pass its deficits on to California ratepayers.

II.

Specific Comments on Intertie Access Policy Issues

The following comments address the five Intertie access policy issues identified on page 7 of BPA's July 15, 1983 notice. In some instances the issues, as drafted by BPA, are in general terms which may be subject to more than one interpretation. Where the issue appears ambiguous or open ended, clarifying interpretation of the issue has been added.

A. How Can BPA Best Determine The Amount Of Intertie Capacity, If Any, Which Is Excess To The Government's Needs?

The "Government's needs" are considered by Edison to be contractual commitments made by BPA to provide or transmit on the

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[5/] See 1983 BPA Rate Proposal, Evaluation of the Record at pp. 284-286 (August 1983)

Intertie certain amounts of generating capacity and energy. BPA's excess Intertie capacity should be determined by adding (1) the capacity, in kilowatts, associated with BPA's firm power arrangements (i.e., purchase, sale, and exchange) with Southwest utilities to (2) BPA's firm transmission service commitments, in kilowatts, to others, and subtracting this sum from BPA's share, in kilowatts, of the firm rating of the Intertie. While BPA must maintain sufficient transmission capacity for its own firm arrangements with Southwest utilities, long-term firm transmission service must also be provided by BPA to enable nonfederal Northwest entities to conduct transactions that are beneficial to such entities. Without such access, the open Intertie access policy established at the time of the formation of the Intertie, which is discussed below in response to Issue B, will be defeated.

BPA Best Provide Access To Northwest Intertie Capacity Which Is Excess To The Government's Needs?

BPA should provide all Northwest entities access to the Intertie. BPA's function should be that of coordinating schedules, operating and maintaining transmission lines and substations, and billing Intertie users for service based on the cost of facilities used.

The best way BPA can provide Intertie access is to not hinder or obstruct access by others by adopting unnecessary or inappropriate procedures and requirements or by establishing rates for service that exceed the cost of providing the service. Access means, in effect, having a transmission path to or from the points where the Pacific Northwest interconnects with the Pacific Southwest. These points are Malin at the California-Oregon border ("COB") for the AC lines and the Nevada-Oregon border ("NOB") for the DC line.

Almost all transactions at COB or NOB are sales from the Northwest to the Southwest. Any attempt by BPA to control access by others to the Intertie would be an attempt to control sales by others at COB and NOB. Such control would be a manipulation of the Intertie marketplace and is inconsistent with the principles and contracts under which the Intertie was constructed.

The Department of the Interior report to Congress recommending construction of the Intertie is replete with statements which demonstrate that both the government and the nonfederal entities in the Northwest contemplated that open access for nonfederal entities in the Northwest to the Intertie would be provided on BPA's portion of the Intertie facilities. 6/ BPA assured both public and private utilities in the Pacific Northwest that they would be allowed access over BPA's portion of the Intertie to the Pacific Southwest markets proportionate to their respective surpluses.7/ The purpose of this assurance of access is very clear.

6/ Department of the Interior, Report to the Appropriations Committees of the Congress of the United States Recommending a Plan of Construction and Ownership of EHV Electric Interties Between the Pacific Northwest and Pacific Southwest (Comm. Print 1964)

7/ Id. at p.27 and p.34

> "The broad participation of all parties concerned with the sale or purchase of Northwest surplus power provides built-in protection against anyone monopolizing either use of the line or the resources or the markets."[8]

The historical development and contractual arrangements established regarding the Intertie mandate that BPA allow access to all entities in the Pacific Northwest with surplus power to sell. BPA should not in any way restrict other entities from access to the Intertie or attempt to control transactions that take place over the Intertie. In hearings before FERC, Charles F. Luce, Bonneville Power Administrator at the time the Intertie was conceived and constructed, stated that BPA promised nonfederal entities full access to the Intertie. He said that BPA had

> "an intense campaign for Bonneville to build every major transmission line in the Pacific Northwest. We fought the efforts of the private companies to build what we regarded as too small and inadequate transmission lines. We said let us build them right and big enough and we will let you on these lines as though they were your own. We will not block you out because we own the lines..."[9]

BPA's proposal to charge for firm transmission service based on "lost opportunity" cost is, in effect, using the ratemaking process to restrict access by others to the Intertie and is contrary to applicable law. For example, the Northwest Regional Preference Act, Public Law 88-552, 16 U.S.C. §837, et seq., (1964) provides not only that BPA must provide common carrier

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[8] Id. at p. 40

[9] Testimony before FERC in Docket Nos. E-7796 and E-7777 (Phase II), January 14, 1981, at transcript page CH-38, 610

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service on its transmision system, but that no contract for firm transmission service can be affected by subsequent increases in BPA requirements for transmission of federal energy. Section 6 provides:

> "Any capacity in Federal transmission lines connecting, either by themselves or with non-Federal lines, a generating plant in the Pacific Northwest or Canada with the other area or with any other area outside the Pacific Northwest, which is not required for the transmission of electric energy, or the energy described in Section 9, shall be made available as a carrier for transmission of other Federal energy between such areas....... No contract for the transmission of non-Federal energy on a firm basis shall be affected by any increase, subsequent to the execution of such contract, in the requirements for the transmission of Federal energy." (Emphasis added)

The House and Senate Reports which accompanied the statute analyzed the relevant portion of Section 6 with the following language:

> "In determining the existence of capacity excess to the needs of the Government, Federal needs reasonably foreseeable may be included, but the secretary may not decline to enter into a wheeling agreement merely because he may have energy available for sale to serve the same load."[10]

The Senate Report further stated that the intertie lines "would be operated as common carriers, with excess capacity available to non-Federal utilities at cost."[11]

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[10] HR Rep. No. 590, 88 Cong. 2d Sess., Reprinted 1964, USCCAN 3342, 3350; Senate Report No. 122, 88 Cong. 1st Sess. 12 (1963).

[11] Id. at 4.

C. What Consideration Should BPA Require To Grant Transmission Rights To Intertie Capacity Otherwise Needed By The Government? How Should The Rights Of Other Entities, Such As Parties To The Exportable Agreement, Be Considered?

In the first question above, "consideration" is interpreted as meaning monetary payment. "Capacity otherwise needed" by the Government could mean capacity needed to satisfy BPA's contractual commitments and obligations, as defined by Edison in Issue A, or additional capacity that would be useful to BPA for transmitting BPA's surpluses on a day-to-day or week-to-week basis. Edison assumes that the latter interpretation is what was intended.

BPA should require the requesting entity to pay BPA's cost of service, based on the facilities used, as consideration for granting transmission rights. Value-of-service or lost-opportunity charges should not be the basis for any payment. FERC, as noted above, opposes value-of-service rates, and probably will react similarly to lost-opportunity charges. BPA should cease consideration of such charges. The desire by BPA to set such rates for wheeling transactions emphasizes BPA's efforts to maintain a monopoly position in the Northwest and on the northern end of the Intertie.[12]

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[12] Please see Exhibit No. WP-83-E-CE-02, at pp. 10-11 filed by Edison in the 1983 BPA rate case (BPA File Nos. WP-83 and TR-83)

BPA's contractual transmission obligations to provide Intertie capacity to other entities should be honored. BPA identified, in its July 15, 1983 notice, Intertie rights belonging to Pacific Power and Light (PP&L), Portland General Electric (PGE), and Washington Water Power (WWP). PGE and WWP have used their Intertie entitlements to enter into firm generating capacity exchange agreements with Edison that have benefited ratepayers in both regions. To continue these beneficial exchanges, BPA should give those entities the opportunity to extend the duration of those transmission services beyond the current expiration dates. BPA should also provide Intertie access to other Northwest entities with surplus capacity or energy to market.

D. What Priorities Should Be Established By BPA In Providing Intertie Access For Deliveries From The Pacific Northwest To The Pacific Southwest?

BPA's first priority as a federal agency should be efficient utilization of the nation's resources.[13] Renewable resources that otherwise will be wasted unless used, such as spilling hydro, which cannot be stored, should be used to displace finite fossil fuels, such as oil, gas, and coal, which can be stored. To ensure optimum displacement and conservation of fossil fuels, especially oil and gas, BPA should not burden Intertie transmission services it provides to others with price control restrictions or charges not related to the cost of services provided. Such restrictions and charges are unfair to ratepayers and do not promote the efficient use of the nation's renewable resources. In order to fulfill BPA's guarantee of equal access for Northwest entities not owning Intertie facilities as testified before FERC by Charles Luce (see page 6 hereof), BPA should offer Intertie access to preference and non-preference entities alike, on a non-discriminatory basis, consistent with the rights and principles established by Congress, as cited above.

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[13] 16 U.S.C. §839.

Among the various services which BPA should provide on the Intertie, firm transmission service should have the highest priority, because firm service is essential for capacity sales and diversity capacity exchanges. Firm transmission service is needed to deliver a firm resource that a purchaser is depending upon for continuity of service to its customers, and that purchaser is paying more for this higher quality service. A lower priority should be given to nonfirm transmission service because associated resource transactions are interruptible on minimum notice and are not essential to service continuity.

E. What Terms Of Service Should BPA Offer For Transmission On the Intertie?

BPA should offer firm two-way service on the Intertie at prices based on the cost of the facilities involved. Firm resources transmitted using such service would have a significantly reduced value if BPA does not commit to providing at least a five-year advance notice, or a longer negotiated advance notice, for termination of firm transmission service. A five-year period is the minimum time needed to replace a firm purchase if another purchase is not available. BPA should also offer interruptible transmission service to enable nonfirm economy energy transactions.

III.

CONCLUSION

Edison appreciates this opportunity to participate in the development of BPA's Intertie access policy. BPA should give consideration to these comments in establishing an Intertie access policy that is fair to all entities affected. BPA should provide all entities, both federal and nonfederal, opportunity for access to the Intertie, and in so doing, BPA should not dictate or interfere with the transactions that take place on the Intertie except as required for maintenance and safety. Both of these objectives were mandated by the original Congressional authorization of the Intertie, and are consistent with the policies of FERC. These objectives can be achieved by BPA providing transmission service at prices based on cost on a non-discriminatory basis to Northwest entities, whether federal or nonfederal, as they enter into power purchase, sale, or exchange agreements with Southwest entities.

Southern California Edison Company

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August 30, 1982

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Dear Ms. Geiger:

Subject: BPA Transmission Policy - File TrP-1

This letter is in response to Mr. Johnson's May 21, 1982 notice to all BPA customers that BPA intends to reopen the formal process of revising its transmission policy. Southern California Edison was not involved in the initial review process and meetings held in 1981; therefore, the following remarks are based on issues briefly described in the May 21, 1982 notice.

In the May 21 notice, under "Scope of Issues for Proposed Transmission Policy," BPA has identified three general areas to be addressed by the final transmission policy. Edison believes that, in addition to efficient utilization of Pacific Northwest transmission resources, "BPA's objectives for wheeling services" (the first general area) should include furthering national objectives of minimizing oil consumption and conserving energy by maximizing transactions among utilities in the Pacific Northwest and Pacific Southwest.

Concerning the second policy area, "types of transmission services BPA intends to offer and their major features," Edison would encourage BPA to provide the Pacific Northwest utilities firm two-way transmission service to facilitate firm capacity and energy exchange arrangements with Pacific Southwest utilities, in addition to non-firm, interruptible transmission service which generally only enables economy energy transactions. Charges for such services should be cost-based and allocated as equitably as practicable to avoid one service subsidizing the other.

THE WASHINGTON WATER POWER COMPANY
RESPONSE TO QUESTIONS FOR NORTHWEST INVESTOR-OWNED UTILITIES

Q1: Is BPA's estimate of the cost of exchange reasonable?

A: Washington Water Power Company has not analyzed the reasonableness of Bonneville's estimate of the cost of exchange. Currently The Washington Water Power Company exchange costs are deemed equal to Bonneville's costs.

Q2: What control over BPA's budget and expenditure is available to BPA's customers?

A: The Company has the ability to comment to Congress on BPA's budget and expenditures. BPA and the Company review and comment on each other's plans within the Company's area. We also comment on and discuss BPA's policies and rate practices.

Q3: What suggestions do Northwest investor-owned utilities have for improving BPA's repayment performance?

A: Obviously, more revenue must be generated by BPA. That can best be performed by increasing their rates and requiring payment on a fixed schedule.

Q4: How long will the residential exchange remain viable for Northwest investor-owned utilities after June 30, 1985?

A: Washington Water Power Company has not analyzed that question. The Regional Power Act intends and requires that the exchange remain viable after 1985.

Q5: What is the position of Northwest investor-owned utilities on HR3177?

A: While we believe there is improvement that can be made in the ratemaking process of BPA, we have not been able to thoroughly analyze this particular proposed legislation to determine if it is the best improvement to be made.

Q6: Do investor-owned utilities favor revised procedure under FERC that would require rates submitted six months prior to the effective date?

A: The Washington Water Power Company's position is essentially the same as stated under question 5.

Q7: What are the conclusions of Northwest investor-owned utilities recent analysis of the cost-effectiveness of resuming construction of WPPSS #3?

A: Resumption of construction of WPPSS #3 is currently being litigated and it would not be appropriate for The Washington Water Power Company to comment on this question. Pleadings in this litigation are a matter of public record.

Q8: How soon could construction resume at WPPSS #3?

A: The Washington Water Power Company does not have the information needed to respond to this question.

Q9: If WPPSS #3 were not completed, could Northwest investor-owned utilities recover their investments in the plant under Washington law?

A: It is our understanding that there is no impediment under either Washington or Idaho law to the recovery of investments in the abandoned plant. However, that does not assure such recovery.

Q10: Do Northwest investor-owned utilities intend to sign BPA's long-term conservation contracts? What elements of the contracts require improvement?

A: The Washington Water Power Company does not intend to sign the Bonneville Power Administration (BPA) long-term conservation contract as presently proposed.

The one element in the contract that requires modification and improvement before participation can be considered is the contract charge provision. While utilities generally agree that the concept of the contract charge is sound, the methodology proposed by BPA is a serious disincentive for utilities to participate. The methodology requires a utility to agree to pay a contract charge each year into the future without knowing how large the charge would be from year to year. The uncertainty of such an unknown charge can expose the utility ratepayers to greater costs than if the programs had been funded independently of BPA.

The Intercompany Pool (ICP), which represents investor-owned utilities in the region, has submitted an alternative methodology for calculation of the contract charge to BPA. The ICP contends that this alternative methodology provides an equitable means by which BPA conservation costs which are not allocated through rates can be repaid.

Q11: Do Northwest investor-owned utilities favor a mitigation by exclusion approach to maintenance of indoor air quality and residential weatherization programs?

A: Very little technical information is presently available regarding the potential harmful effects of indoor air quality degradation. Because of the uncertainty and lack of basic information available, The Washington Water Power Company does not favor a "mitigation by exclusion" approach to indoor air quality. To exclude specific homes from house-tightening would drastically reduce energy conservation benefits to the region due to a perceived risk which has neither been identified nor quantified.

NINETY-EIGHTH CONGRESS

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October 18, 1983

Peter Johnson, Administrator
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

Dear Mr. Johnson:

In preparation for my Subcommittee's hearings on BPA scheduled for October 27 and 28, I have reviewed your testimony in previous hearings before committees of the Congress.

I would like to bring to your attention the enclosed record of a hearing conducted on May 25, 1982, by the House Interior Subcommittee on Oversight and Investigations. In that hearing you repeatedly denied that the WPPSS bond issue then prepared for sale was intended to circumvent the application of Initiative 394 to WPPSS 3. On page 25 of the printed hearing record, for example, you stated that the $215 million of the bond sale earmarked for WPPSS 3 "gets us to the November election of 1982", the first practical opportunity for Washington voters to approve further bond sales for WPPSS 3. On page 27 of the record, I even apologized to you for misinterpreting the preliminary bond statement as stating that the funds dedicated to WPPSS 3 would permit construction to continue into 1983.

I now withdraw my apology. In fact, the last WPPSS bond sale included not $215 million but $305 million for WPPSS 3. And the official bond statement (p. 7) includes this:

> Based upon current cash flow projections, the Supply System estimates that moneys currently available (including the proceeds of the 1982 Net Billed Bonds), together with investment income thereon, will be sufficient to meet cash flow requirements on Project No. 2 until mid-August 1983, and on Project No. 3 until late June 1983.

In other words, just prior to the effective date of Initiative 394, you, as BPA Administrator, approved a WPPSS bond sale of $680 million, $305 million of which was dedicated to WPPSS 3. This was designed to carry WPPSS 3 through the first 6 months of 1983--well beyond the November 1982 election. You did this in June 1982, just days after this hearing, without notifying me or the Subcommittee on Oversight and Investigations that your statements at the hearing were no longer accurate.

At the beginning of June 1983, there remained $108.2 million in the WPPSS 3 accounts, along with another $161.8 million of WPPSS 3 funds held by the bond trustee. Thus, it is clear that the project did not require the extra $90 million in order to continue construction while an election under Initiative 394 could be conducted.

We both know, of course, that Initiative 394 was later gutted, thanks to the refusal of Washington's Attorney General to appeal the litigation to the U.S. Supreme Court. This, however, does not excuse your conduct. As of June 1982, Initiative 394 was on the books and was to be obeyed. The last minute addition to the bond sale of another $90 million for WPPSS 3 had only one purpose--to evade the Initiative by postponing the opportunity for a vote of the people. In the meantime, WPPSS and BPA planned to make the commitment to WPPSS 3 irrevocable by spending so much more that the plant might later be found to be "cost-effective" and might conceivably win voter approval for additional bond sales.

As it is, the cost-effectiveness of completing WPPSS 3 is now again in question, after WPPSS and BPA have spent still another $305 million of ratepayer funds. when, Mr. Johnson, will this end? I honestly would appreciate a realistic, forthright, personal answer to this.

Sincerely,

JIM WEAVER, Chairman
Subcommittee on Mining,
Forest Management and
Bonneville Power Administration

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MEMORANDUM October 24, 1983

TO: Subcommittee members

FROM: Jim Weaver, Chairman
Subcommittee on Mining,
Forest Management and
BPA

RE: Northwest Power Planning
Council's refusal to
testify at Subcommittee's
October 28 hearing

Last Friday evening Subcommittee staff was notified that the Northwest Power Planning Council's eight members had decided not to participate in the Subcommittee's hearings scheduled for October 27 and 28. The Council had earlier agreed to testify at the October 28 hearing on the cost-effectiveness of completing the Washington Public Power Supply System's nuclear project # 3, (WPPSS # 3), and BPA's conservation programs and contracts. The October 27 hearing will deal with BPA revenue, repayment and ratemaking.

During the past month, the Council has been issuing preliminary results of its study on the cost effectiveness of completing WPPSS 3. Even though the cost of completing this project has been estimated as at least $2 billion dollars. members of the Council and the Council's staff have repeatedly urged that construction on the plant be re-started as soon as possible.

Whether WPPSS 3 is completed or not will have a major effect on Northwest utility rates. It is, therefore, appalling that the Council would choose not to appear before the Subcommittee to discuss this crucial issue.

I strongly urge you to read the following summary of the Council's statements on WPPSS 3. This summary sheds some light on why the Subcommittee is reluctant to face Subcommittee scrutiny.

In May 1983, the Northwest Power Planning Council issued its first plan. This plan simply assumed that WPPSS 2, 3 and 1 would be completed and commence service in 1984, 1987, and 1991, respectively, even though in April 1982 the Bonneville Power Administration (BPA) had decided to mothball WPPSS 1 and was during May 1983 considering whether to halt construction on WPPSS 3 as well. Later in May, BPA decided to put WPPSS 3 into a "preservation" state for at least 3 years, delaying completion until at least 1989. Thus, within a month of its issuance, the Council's plan had become obsolete.

On June 10, 1983, the Subcommittee on Mining, Forest Management, and BPA conducted a hearing that addressed the cost-effectiveness of attempting to complete WPPSS 3. At the hearing the Council stated:

> The Council did estimate the levelized cost of energy from the three plants in constant 1980 dollars to be approximately 1.8 cents per kilowatt hour for WPPSS 2; 2.5 cents per kilowatt hour for WPPSS 3; and 3.0 cents per kilowatt hour for WPPSS 1. These levelized cost estimates can be compared to an average cost for the Council's conservation measures of 1.8 cents per kilowatt hour and a cost of 4 cents per kilowatt hour saved for marginal conservation measures. . . . These estimated energy costs compare favorably with other resources included in the

Council's plan, including hydro, cogeneration and coal plants that are included in the late 1990s.[1]

The Council also stated that delaying completion of WPPSS 3 beyond 1987 would likely have a "substantial" adverse impact on rates.[2]

During the hearing, however, the Council representatives admitted that its analysis reflected only costs to be incurred in 1984 and later and that it had assumed that construction on WPPSS 3 had proceeded full speed ahead during all of 1983, sinking another $200 million or more into the project. These costs were not, in fact, incurred and can still be avoided. In addition, the Council conceded that its projected 3% real cost of capital did not reflect the fact that WPPSS 3 bonds then carried (and still do carry) a nominal interest rate exceeding 16%, or at least 10% real.[3]

Despite these admissions of flaws in its analysis, the Council appeared on August 3 and again on September 9 before the Senate Committee on Energy and Natural Resources, chaired by Senator McClure of Idaho. These hearings concerned Senator McClure's proposal to create a new "entity" to finance an immediate resumption of construction at WPPSS 3. At the September 9 hearing, Council member Roy Hemmingway announced that the

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[1] Northwest Power Planning Council, Answers to Questions by the Subcommittee, in **Washington Public Power Supply System: Financial Meltdown**, Hearing before the Subcommittee on Mining, Forest Management, and the Bonneville Power Administration, June 10, 1983, p. 295 [referred to as Hearings].

[2] Hearings, p. 291-92.

[3] Hearings, pp. 57-58.

Council would present its final cost-effectiveness analysis at the Council meetings on October 19 and 20. In the meantime, said Hemmingway, "The Council would not recommend that the committee delay consideration of this legislation pending the outcome of the Council's cost-effectiveness analysis." [4] Thus, the Council did not oppose action aimed at immediate restart of WPPSS 3 construction, even though it had not completed its cost-effectiveness analysis.

Based upon the Council's schedule for issuing its WPPSS 3 cost-effectiveness study by October 19 or 20, the Subcommittee scheduled hearings concerning this and other matters for October 27 and 28. In the meantime, the Council announced at several meetings throughout the Northwest that completing WPPSS 3 would be cost-effective. In Boise, Idaho, on September 22, Roy Hemmingway appeared on television to state:

> We don't want to experience the consequences of not getting on with it [building WPPSS 3] quickly. The power is going to be needed, we can't get it all from conservation, and this [WPPSS 3] is the most cost-effective way of getting the power.

The Council's executive director, Ed Sheets, stated: "If there is even a small chance of losing the plant, it may be better to go ahead" with construction.[5] Jim Litchfield, director of the Council's projects division, added:

> There would be a very small savings if we delayed the project, but it would be a very large cost if we

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[4] Northwest Power Planning Council, Statement Before the Senate Energy and Natural Resources Committee Regarding S. 1701, September 9, 1983, p. 6 (Seattle, Washington).

[5] Seattle Times, September 22, 1983, p. A18.

> lost the plant later. It's probably prudent to move right ahead with construction.[6]

On October 5 in Helena, Montana, Council spokesmen continued to assert that immediate restart of WPPSS 3 construction would be cost-effective. These comments provoked in Northwest newspapers headlines such as "Study Finds Savings in Reviving N-Plant." [7] The Council staff stated that the least costly path would be to resume construction of WPPSS 3 by January 1, 1984, and proceed on a "slow track" to completion by the end of 1988. Delaying restart until 1989 with completion by 1993 would cost an additional $100 million, said the staff, while terminating WPPSS 3 and WPPSS 1 would cost $800 million.

Now, offered an opportunity to defend its position before the Subcommittee, the Council has refused to appear at the October 27 and 28 hearings. And, despite numerous requests, the Subcommittee staff has yet to receive a single shred of paper showing the Council's underlying assumptions or methodology, or even the preliminary results of the Council's analyses.

The Council was created by the Pacific Northwest Electric Power Planning and Conservation Act of 1980, Public Law 96-501. The Council is funded through BPA revenues. During FY 1982 the Council spent $5.7 million. Expenditures during FY 1983 were $5.6 million. The Council has proposed a FY 1984 budget for itself of $6.1 million, all paid by a surcharge on firm power sales of BPA. Despite these millions of dollars, the Council is unable to respond to simple information requests from the Subcommittee and has now refused to appear at a scheduled Subcommittee hearing.

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6. Portland Oregonian, September 23, 1983, p. C8.

7. Spokane Spokesman Review, October 6, 1983. p. 6.

CONGRESSMAN RON WYDEN
TESTIMONY BEFORE THE SUBCOMMITTEE ON MINES, FOREST MANAGEMENT AND THE BPA
OCTOBER 27, 1983

Mr. Chairman, I thank you for the opportunity to testify on HR 3177, the Bonneville Power Administration Fair Ratemaking Act of 1983.

Since Congressman Swift and I introduced this bill in May, we have garnered the bipartisan support of 10 members from the Pacific Northwest.

Indeed, I am pleasantly surprised at the broad-based support shown for our legislation by virtually every group with a stake in BPA's ratemaking process -- from public interest groups, private utilities, public utilities, state and local governments to large industrial customers of the BPA.

To illustrate this broad-based support, with your permission Mr. Chairman, I would ask that a summary I have prepared of testimony received on HR 3177 during the Energy Conservation & Power subcommittee's oversight hearing on June 13th be made a part of the record of this hearing.

As the summary of the June 13th testimony indicates, the objections to the present BPA ratemaking process fall into two categories.

The first concern is that the BPA staff serves essentially as prosecutor, judge and jury. The staff formulates the initial rate proposal, presents testimony to defend the proposal, produces a "Staff Evaluation of the Record," and then writes the Administrator's final decision.

The second concern is that final rate decisions are sometimes made using information that was not available for public scrutiny. In the past, the Administrator has relied on documents which other parties have not had an opportunity to examine or challenge. Final cost-of-service, rate design, and revenue requirements studies -- that often vary substantially from preliminary studies -- have been prepared and distributed after the hearings are concluded.

The goal of our legislation is straightforward: to ensure that the process by which BPA rates are determined is a fair and open one, and that the decisions made at the regional level are sound ones.

By making the ratemaking process credible and fair at the outset, we will be able to resolve disputes at the regional level, without resorting to an appeals process that produces lingering uncertainty.

We are all familiar with the tremendous gap between the time BPA implements their new rates and when the Federal Energy Regulatory Commission grants final approval. Even now, two prior rate cases are being challenged in the US Ninth Circuit Court of Appeals. In fact, I am informed that another suit concerning the most recent rate case will be filed this week.

Given BPA's precarious financial footing, I shudder to think of the ramifications if BPA were ordered to refund revenues collected as a result of litigation on prior rates.

Our bill will prevent these cumbersome and time-consuming challenges to BPA's wholesale ratemaking by ensuring credibility and fairness from the very beginning of the ratemaking process.

The first step is to make the hearing officer an independent decision-maker.

In contrast to the present hearing officer role -- merely ruling on admissibility of evidence -- our bill would require the hearing officer to evaluate evidence -- both that of BPA staff and the parties -- and render an initial decision for the Administrator of BPA to consider.

Second, our bill assures the Administrator's final decision is made on the record of the hearing.

Any new documents, studies or revised rates produced by the Administrator must be a part of the record, subject to reasonable opportunity for cross-examination and -- if good cause is shown -- rebuttal.

Finally, our bill resolves any question concerning the right of the Power Planning Council to participate in the ratemaking process. No one has challenged the Council's right to participate to date; nor in our opinion would any valid arguments of law support such a challenge. Nevertheless, our bill resolves any doubt that might arise.

I would like to conclude with a couple of observations, Mr. Chairman.

Our bill preserves the Administrator's authority to set rates. The Administrator may establish final rates that are different than those of the hearing officer. All our bill does is to require that the Administrator's decision be made on the record and that the Administrator provide a full and complete justification of the differences between the final rates he or she sets and those established by the hearing officer.

Thus, we recognize the possibility of arriving at two different decisions from the same record. Indeed, the recent FERC Merwin dam decision, reversing the ruling of their Administrative Law Judge, illustrates this well. What we are striving for is better articulation of the grounds on which the Administrator's final decision is made, rather than simply allowing the decision to be cloaked in the veil of the "Administrator's discretion."

Some have raised the objection that, under our bill, the process for formulating and approving rates will become longer and more drawn out.

Just the opposite should occur. If one looks at the overall length of time from rate proposal to final rate approval, it should be obvious that a more credible process and hearing record developed at the outset will reduce the time to finally approve BPA rate proposals.

But don't just take my word for it. Here is what the FERC had to say in an August 1st letter to me:

> "A predictable consequence of these changes will be that a better administrative record supporting rates established by the Administrator should be developed. The improved quality of the administrative record may facilitate the Commission's review of the Administrator's rates, possibly resulting in a more expeditious decision."

WPPSS legislation now pending reinforces the need for a credible ratemaking process.

The WPPSS bill would increase the Administrator's discretion tremendously with respect to committing the ratepayers to cover the additional one billion dollars needed to complete WPPSS plant 3.

That means one billion dollars worth of rate hikes to spread around. If ever there was a time when ratemaking will have to be credible and fair, it is now.

Our bill, though narrow in scope, responds to the pervasive criticisms of the present ratemaking process we have heard from virtually every customer group in the Pacific Northwest.

I appreciate the opportunity to testify on HR 3177 and I am hopeful that we can count on your support in enacting this legislation.

Thank you.

SUMMARY OF REMARKS ON HR 3177, THE BONNEVILLE POWER ADMINISTRATION FAIR RATEMAKING ACT OF 1983: JUNE 13 NORTHWEST POWER ACT OVERSIGHT HEARINGS IN PORTLAND & SEATTLE

STATE AND LOCAL GOVERNMENT

Public Utility Commissioner of Oregon John Lobdell:

"The point that I want to address is that of almost total lack of accountability on the part of the Bonneville Power Administration. In particular, Bonneville is not held accountable in two important areas: setting rates and the extent to which it implements the Regional Plan

"The lack of accountability in rate-setting is well-known. BPA staff formulates the initial rate proposal and presents its case before a BPA administrative law judge, whose function is merely to conduct the hearing. The staff then evaluates the record, and proposes a final determination to the BPA administrator. BPA staff even produces studies and evidence after the record is closed. This would be akin to a private utility filing, hearing, defending, and deciding on its own rates, with some evidence held secret--a process which would hardly be termed open and accountable....I support HR 3177, introduced by Representative Wyden, as an invaluable step towards making BPA's rate-setting procedure more accountable to Pacific Northwest interests."

City of Tacoma (Mayor Doug Sutherland):

"It is generally recognized that the BPA ratemaking process provided by the Regional Act has led to significant controversy and uncertainty....Tacoma has carefully reviewed HR 3177 and agrees with its provisions. The concept of a hearing officer playing an expanded role will hopefully lead to objective, balanced, and less controversial BPA rates."

Portland City Commissioner Mike Lindberg:

"I am in support of the concept embodied in HR 3177, a bill which addresses BPA's ratemaking process and the need for public involvement and accountability.

As a local government official, I would welcome the opportunity to participate in a more open ratemaking process....As the BPA now controls both the development and implementation of its rate structure, these functions need to be separated."

PRIVATE UTILITIES

Pacific Power and Light (Robert Moench, Vice President):

> "Pacific supports the enactment of HR 3177. The addition of an independent hearing examiner and opportunities for reasonable cross-examination will enhance the fairness and credibility of the Bonneville ratemaking process."

Puget Sound Power & Light:

> "HR 3177 is a technical amendment to the Regional Power Act which is consistent with the original purposes of the Act and with other legislation governing Bonneville ratemaking....It is a good amendment which should be widely supported by Bonneville's customers."
>
> "The bill emphasizes fairness in the ratemaking process by requiring the hearing officer to be an independent decision maker. The bill also aims to solve the problem of additional studies and revised rates becoming part of the record without adequate opportunity for cross-examination. This can provide some better assurance of procedural fairness to parties in the rate process."

Portland General Electric (James Durham, Vice-President and Senior Counsel):

> "We share the concerns addressed in HR 3177. The BPA ratemaking process has evolved into a frustrating experience...In some cases, its rate decisions appear not to be based on the hearing record."
>
> "The problems we have experienced in the past are reflected in our testimony...whereby history gets rewritten between the hearing and the ultimate decision of the Administrator...an independent hearing officer to establish the record and make findings of fact is extremely important."

Northwest Natural Gas (Paul Hathaway, Senior Vice President):

> "....[S]treamlining the proceedings used to make electricity rates will result in better rates, and better public relations. I think HR 3177 is a step in that direction. For that reason I support the effort to make the BPA ratemaking procedures more efficient. HR 3177 has an outstanding feature with which I particularly agree. That is, the hearing officer must be independent and must file findings of fact after receiving proposed findings of fact and conclusions of law from participating persons."
>
> "At all costs, BPA staff should not be allowed to be judge, jury, executioner, and defendant in its own cases.

PUBLIC UTILITIES

Public Power Council (Jere Overs, Chairman):

> "The Public Power Council strongly supports HR 3177. The Public Power Council and other BPA customer groups have long sought an independent hearing officer who would submit findings of fact and conclusions of law to the administrator final decision. We applaud this effort by our Northwest Congressman."

Snohomish County Public Utility District (William Hulbert, Jr., Manager,):

> "We concur and heartily endorse the principles of HR 3177. We have some problems about the appointment of the hearing judge or whatever he might be called, making sure it is an arms length type of thing."

PUBLIC INTEREST SECTOR

Northwest Conservation Act Coalition (Mark Reis, Executive Director):

> " This proposal is also a worthy addition to the 'Conservation Act.'...[T]he determination of BPA's rates is as important a decision as any other to the residential, commercial and industrial ratepayers of the region....Yet, to date the BPA ratemaking procedure remains unchanged by the Regional Act. Final decisions are political, not technical or legal ones. HR 3177 would make some valuable changes in that process."

Natural Resources Defense Council, Inc. (Ralph Cavanagh, Senior Staff Attorney):

> "Rate-making and other BPA proceedings extend for months, if not years; episodic appearances [by the BPA] at 'public forums' are no substitute for continuous involvement....HR 3177 offers a number of procedural reforms that would eliminate many of the more arbitrary features of BPA rate-making."

OTHER ENDORSEMENTS OF HR 3177:

Industrial Customers of Northwest Utilities

Northwest Pulp and Paper Association

Seattle City Light

Evergreen Legal Services

Honorable Mary Hall, Commissioner, Washington Utilities and Transportation Commission. (Personal support, not Commission's).